UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ____________**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED TRANSMISSION OPERATIONS AND INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION RELIABILITY STANDARDS

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March 18, 2015

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Pursuant to Section 215(d)(1) of the Federal Power Act[1] and Section 39.5[2] of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval the following nine proposed Reliability Standards (Exhibit A):[4]

- TOP-001-3 (Transmission Operations);
- TOP-002-4 (Operations Planning);
- TOP-003-3 (Operational Reliability Data);
- IRO-001-4 (Reliability Coordination – Responsibilities);
- IRO-002-4 (Reliability Coordination –Monitoring and Analysis);
- IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-2 (Reliability Coordinator Data Specification and Collection);
- IRO-014-3 (Coordination Among Reliability Coordinators); and
- IRO-017-1 (Outage Coordination).

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act ("FPA") on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

NERC requests that the Commission approve the proposed Reliability Standards and find that each is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As discussed further below, the proposed Reliability Standards replace the Reliability Standards currently pending with the Commission in Docket Nos. RM12-12-000, RM13-14-000 and RM13-15-000 (the "Pending TOP/IRO Standards).[5]

NERC also requests approval of: (i) revised definitions for the NERC Glossary terms "Operational Planning Analysis" and "Real-time Assessment" (Exhibit A); (ii) the Implementation Plan for the proposed Reliability Standards and definitions (Exhibit B); and (iii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and J). Finally, NERC requests retirement of the following Reliability Standards.

- IRO-001-1.1 (Reliability Coordination – Responsibilities and Authorities);
- IRO-002-2 (Reliability Coordination — Facilities)
- IRO-003-2 (Reliability Coordination – Wide-Area View);
- IRO-004-2 (Reliability Coordination – Operations Planning);
- IRO-005-3.1a (Reliability Coordination – Current Day Operations);
- IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-1a (Reliability Coordinator Data Specification and Collection);
- IRO-014-1 (Coordination Among Reliability Coordinators);
- IRO-015-1 (Notifications and Information Exchange Between Reliability Coordinators);
- IRO-016-1 (Coordination of Real-time Activities Between Reliability Coordinators);
- PER-001-0.2 (Operating Personnel Responsibility and Authority);
- TOP-001-1a (Reliability Responsibilities and Authorities);
- TOP-002-2.1b (Normal Operations Planning);
- TOP-003-1 (Planned Outage Coordination);
- TOP-004-2 (Transmission Operations);
- TOP-005-2a (Operational Reliability Information);

[5] Concurrent with this filing, NERC is submitting a motion to withdraw the Reliability Standards pending Commission approval in those dockets. *Notice of Withdrawal of the North American Electric Reliability Corporation*, Docket Nos. RM13-12-000, RM13-14-000, and RM13-15-000 (Mar. 18, 2015).

- TOP-006-2 (Monitoring System Conditions);
- TOP-007-0 (Reporting System Operating Limit and Interconnection Reliability Operating Limit Violations); and
- TOP-008-1 (Response to Transmission Limit Violations).

As required by Section 39.5(a) of the Commission's regulations,[6] this Petition presents the technical basis and purpose of the proposed Reliability Standards and definitions, a summary of the development history (Exhibit K), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[7] (Exhibit C).

This Petition is organized as follows: Section I of the Petition presents an executive summary of the proposed Reliability Standards. Section II of the Petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides background on the regulatory structure governing the Reliability Standards approval process, as well as information on the development of the proposed Reliability Standards. Section IV of the Petition then discusses the proposed Reliability Standards and definitions in detail, including the purpose and improvements of the proposed Reliability Standards and definitions. Section IV also explains how the proposed Reliability Standards address:

- the recommendations in the joint FERC and NERC report on the 2011 Arizona-Southern California outages ("Southwest Outage Report") (*see also* Exhibit F),[8]

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[6] 18 C.F.R. § 39.5(a) (2014).

[7] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[8] FERC and NERC, *Arizona-Southern California Outage on September 8, 2011, Causes and Recommendations* (Apr. 27, 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

- concerns raised by the Commission in the November 21, 2013 *Notice of Proposed Rulemaking*, which proposed to remand the Pending TOP/IRO Standards (the "TOP/IRO NOPR") (*see also* Exhibit G),[9] and

- outstanding FERC directives related to the proposed Reliability Standards (*see also* Exhibit H).

I. EXECUTIVE SUMMARY

The proposed Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards address matters that are fundamental to grid reliability as they pertain to the coordinated efforts to plan and operate the Bulk Electric System in a reliable manner under both normal and abnormal conditions. As discussed further below, the proposed Reliability Standards consolidate many of the currently effective TOP and IRO Reliability Standards and replace the Pending TOP/IRO Standards in addressing the roles and responsibilities of Reliability Coordinators, Transmission Operators and Balancing Authorities with respect to planning and operating the Bulk Electric System. The proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the Bulk Electric System is operated within pre-established limits while enhancing situational awareness and strengthening operations planning.

The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. Among other things, the proposed Reliability Standards help to ensure that Reliability Coordinators and Transmission Operators work together, and with other functional entities, to operate the Bulk Electric System within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"). SOLs and IROLs are

[9] *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013) ("TOP/IRO NOPR").

vital concepts in NERC's Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of Transmission Operators, although certain requirements apply to the roles and responsibilities of the Balancing Authority. The proposed IRO Reliability Standards set forth the responsibility and authority of Reliability Coordinators to provide for reliable operations. Reliability Coordinators have an essential role in ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the Bulk Electric System.

The proposed Reliability Standards improve upon the currently effective TOP and IRO Reliability Standards by eliminating gaps, ambiguities, and redundancies, and by improving the overall quality of the TOP and IRO Reliability Standards. Specifically, the proposed Reliability Standards include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

For the reasons discussed herein, NERC respectfully requests that the Commission approve the proposed Reliability Standards, the proposed revised definitions, and the proposed retirements.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[10]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[12] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[13] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[14] of the Commission's regulations requires the ERO to file with the

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[10] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

[11] 16 U.S.C. § 824o (2012).

[12] *Id.* § 824(b)(1).

[13] *Id.* § 824o(d)(5).

[14] 18 C.F.R. § 39.5(a).

Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[15] and Section 39.5(c)[16] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards and definitions were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[17] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[18] In its order certifying NERC as the Commission's Electric Reliability Organization, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability

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15 16 U.S.C. § 824o(d)(2).

16 18 C.F.R. § 39.5(c)(1).

17 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

18 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Standards[19] and thus satisfies certain of the criteria for approving Reliability Standards.[20] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits a proposed Reliability Standard to the Commission for approval.

C. FERC Proceeding History

As noted above, the proposed Reliability Standards are intended to replace the Pending TOP/IRO Standards, which consist of the following:

- *Reliability Standard TOP-006-3 (Monitoring System Conditions)*, which NERC filed on April 5, 2013 in Docket No. RM13-12-000. The proposed revisions to Reliability Standard TOP-006-3 were intended to divide the reporting responsibilities of Balancing Authorities and Transmission Operators into separate requirements.

- *Reliability Standards TOP-001-2 (Transmission Operations), TOP-002-3* (*Operations Planning), TOP-003-2 (Operational Reliability Data) and PRC-001-2 (System Protection Coordination)*, which NERC filed on April 16, 2013, in Docket No. RM13-14-000. These Reliability Standards were intended to replace the eight currently effective TOP Reliability Standards.[21]

- *Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators)*, which NERC filed on April 16, 2013, in Docket No. RM13-15-000. These four Reliability Standards were intended to replace six currently effective IRO Reliability Standards (IRO-001-1.1, IRO-002-2, IRO-005-3a, IRO-014-1, IRO-015-1, and IRO-016-1).

On November 21, 2013, the Commission issued the TOP/IRO NOPR, proposing to approve proposed Reliability Standard TOP-006-3 but remand the other Pending TOP/IRO Standards. A

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[19] ERO Certification Order at P 250.

[20] Order No. 672 at PP 268, 270.

[21] The changes in proposed Reliability Standard PRC-001-2 were administrative in nature and limited to removal of three requirements in currently effective Reliability Standard PRC-001-1 that were addressed in proposed Reliability Standard TOP-003-2. Concurrent with this filing, NERC is requesting withdrawal of its request for approval of PRC-001-2 but is not proposing herein any changes to that standard. Any changes corresponding changes to PRC-001 are being addressed in Project 2007-06.2 – Phase 2 of System Protection Coordination.

summary of the Commission's concerns raised in the TOP/IRO NOPR are included in Section IV as well as Exhibit G.

In response to the TOP/IRO NOPR, on December 20, 2013, NERC filed a motion requesting that the Commission defer action on the Pending TOP/IRO Standards, until January 31, 2015, to allow NERC time to consider the reliability concerns raised by the Commission and revise the Pending TOP/IRO Standards as necessary.[22] The Commission granted that motion on January 14, 2014.[23] NERC has been providing the Commission quarterly updates on the status of its standards development process to revise the Pending TOP/IRO Standards. In its quarterly report for the fourth quarter of 2014, filed January 2, 2015, NERC informed the Commission that it needed additional time to obtain NERC Board of Trustees ("Board") adoption of proposed Reliability Standard TOP-001-3 at the Board's regularly scheduled meeting on February 12, 2015.

D. Project 2014-03 – Revisions to TOP and IRO Standards

In response to the TOP/IRO NOPR and consistent with NERC's responsibility as the ERO to develop Reliability Standards that provide for an adequate level of reliability of the Bulk-Power System, NERC, with Commission and industry support, initiated Project 2014-03 to develop revisions to the Pending TOP/IRO Reliability Standards and fulfill the goals of the original projects: Project 2006-06 Reliability Coordination[24] and Project 2007-03 Real-time Operations.[25]

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22 *Motion of the North American Electric Reliability Corporation to Defer Action*, Docket No. RM13-12-000 (December 20, 2013).

23 *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 146 FERC ¶ 61,023 (2014).

24 The Project 2006-06 development webpage is available at http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx.

25 The Project 2007-03 development webpage is available at http://www.nerc.com/pa/Stand/Pages/Real-time_Operations_Project_2007-03.aspx.

The objective of Project 2014-03 was to provide clear, unambiguous Reliability Standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities operate the interconnected transmission system in a safe and reliable manner. In addition, the Project 2014-03 standard drafting team considered recommendations from the Independent Experts Review Panel ("IERP").[26]

As discussed below, the proposed Reliability Standards reflect an improved, more robust set of Reliability Standards. The NERC Board adopted the proposed Reliability Standards and definitions on November 13, 2014, with the exception of proposed Reliability Standard TOP-001-3, which the Board adopted on February 12, 2015.

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C, the proposed Reliability Standards and definitions satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The development of the proposed Reliability Standards was informed by recent industry reports and initiatives, including two NERC-sponsored technical conferences in March 2014,[27] the Southwest Outage Report, the IERP Report, the NERC Operating Committee consideration of the IERP report (Exhibit I), and the Commission's TOP/IRO NOPR.

The following section provides: (1) an explanation of the purpose and improvements in the proposed Reliability Standards and modified NERC Glossary definitions; (2) a description of each

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[26] In 2013, NERC formed the IERP, which consisted of five industry experts, to independently review the NERC Reliability Standards to assess the content and quality of the Reliability Standards, including the identification of Bulk-Power System risks. The IERP's final report (the "IERP Report") is available at : http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

[27] The slides from the conferences are available at: http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/top_iro_technical_conference_presentation_20140306.pdf.

of the proposed definitions and requirements in the proposed Reliability Standards; and (3) an explanation of the manner in which the proposed Reliability Standards address the recommendations in the Southwest Outage Report, the concerns raised in the TOP/IRO NOPR, and outstanding FERC directives related to the proposed Reliability Standards.

A. Purpose of and Improvements in the Proposed Reliability Standards

1. Purpose

The proposed Reliability Standards address the important reliability goal of setting forth the requirements applicable to Reliability Coordinators, Transmission Operators, and Balancing Authorities with respect to planning and operating the Bulk-Power System, including requirements for operating the interconnected transmission system within predetermined operating limits. The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The proposed Reliability Standards consolidate the currently effective TOP and IRO Reliability Standards, providing a more precise set of Reliability Standards addressing operating responsibilities. The mapping document, provided as Exhibit D hereto, shows how the currently effective Reliability Standards map to the proposed Reliability Standards.

The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of Transmission Operators. Among other things, the proposed revisions to the TOP Reliability Standards help ensure that Transmission Operators plan to operate within all SOLs.

The proposed IRO Reliability Standards, which complement the proposed TOP Standards, are designed to ensure that the Bulk Electric System is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions. The proposed IRO Reliability

Standards set forth the responsibility and authority of Reliability Coordinators to provide for reliable operations. Reliability Coordinators have an essential role in ensuring reliable operations, as they are the functional entities with the highest level of authority and have the wide-area view of the Bulk Electric System.[28]

2. Improvements

The proposed Reliability Standards improve upon the currently effective TOP and IRO Reliability Standards by eliminating gaps, ambiguities, and redundancies, and by improving the overall quality of the TOP and IRO Reliability Standards. Specifically, the proposed Reliability Standards include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data.

a) Operating Within SOLs and IROLs

An SOL is defined in the NERC Glossary as:

> The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:
>
> - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
> - Transient Stability Ratings (Applicable pre- and post- Contingency Stability Limits)
> - Voltage Stability Ratings (Applicable pre- and post- Contingency Voltage Stability)
> - System Voltage Limits (Applicable pre- and post- Contingency Voltage Limits)"

[28] *See* Order No. 693 at P 1582 "the reliability coordinator is the highest authority in matters affecting reliability of the Bulk-Power System."

An IROL is defined as:

> A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

As the Commission has noted, during deteriorating system conditions, an SOL can rapidly degrade into an IROL.[29] When any Facility Rating or Stability Limit is exceeded, or expected to be exceeded, these conditions should be mitigated to avoid the possibility of further deteriorating system conditions and the potential for a Cascading event.

The proposed Reliability Standards improve upon existing obligations for Transmission Operators and Reliability Coordinators to help ensure the Bulk Electric System is operated within predetermined operating limits. Specifically, SOLs, which must be monitored by Transmission Operators, include Ratings and limits necessary to ensure reliable operation within acceptable reliability criteria, as determined pursuant to Facilities Design, Connections and Maintenance ("FAC") Reliability Standards. In the proposed IRO Reliability Standards, Reliability Coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require the Reliability Coordinator to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.[30]

When a Transmission Operator or Reliability Coordinator, based on its analysis and monitoring of SOLs and/or IROLs, identify a violation of operating limits, the proposed TOP and

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[29] TOP/IRO NOPR at P 52.

[30] *See* i*d*. As the Commission noted, "[d]uring deteriorating system conditions, an SOL can rapidly degrade into an IROL.... Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded." *Id.*

IRO Reliability Standards set forth the requirements for applicable entities to resolve the situation within specified timeframes. Specifically, proposed Reliability Standard TOP-001-3 requires that all violations of IROLs be resolved within the IROL $T_{V,}$[31] which is a technically-based performance expectation that essentially provides that IROL violations cannot exceed 30 minutes, which is consistent with the 30-minute criteria contained in existing TOP Reliability Standards. This proposed revision provides consistency with the Reliability Coordinator requirements contained in currently effective Reliability Standard IRO-009-1. The proposed Reliability Standards also include revisions that will require resolution of SOL violations within specified timeframes that are based on Ratings methodologies developed pursuant to the FAC Reliability Standards and coordinated between the Transmission Operator and Reliability Coordinator.

b) Improved Definitions

The proposed Reliability Standards also use certain foundational NERC Glossary terms, the definitions for which have been improved as part of Project 2014-03. Specifically, NERC is proposing revised definitions for "Operational Planning Analysis" and "Real-time Assessment." As described below, the proposed definitions provide significant additional detail over the currently effective definitions to enhance the consistency and the reliability benefit of Operational Planning Analyses and Real-time Assessments. For example, the proposed definition of Real-time Assessment includes several inputs that were identified as contributing to past outages on the Bulk Electric System, which, in turn, will enhance situational awareness.[32]

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[31] IROL T_v is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "[t]he maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes."

[32] The proposed definition of Real-time Assessment is "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System

Additionally, the proposed Reliability Standards now use the proposed NERC Glossary term "Operating Instruction"[33] instead of the term "reliability directive." The proposed NERC Glossary term "Operating Instruction" defines the scope of commands that are covered by the proposed TOP and IRO Reliability Standards.

c) Situational Awareness

The proposed Reliability Standards also improve upon existing situational awareness requirements. Collectively, the revised definition of Real-time Assessment and associated requirements for Real-time monitoring and Real-time Assessments in proposed Reliability Standards TOP-001-3 and IRO-008-2 provide for consistency in the operations of the Transmission Operator and Reliability Coordinator, giving clear definition of responsibilities and avoiding potential gaps. For example, the proposed TOP Reliability Standards include a requirement for Transmission Operators to perform Real-time Assessments at least once every 30 minutes. The requirement for Transmission Operators to assess system operating conditions on a frequent basis, which is analogous to an existing requirement in the currently effective IRO Reliability Standards requiring Reliability Coordinators to perform Real-time Assessments, will improve situational awareness and reinforce the responsibilities outlined in the NERC Functional

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and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)" Several inputs are based on the Southwest Outage Report recommendations as described in Exhibit F.

[33] The defined term "Operating Instruction" was developed along with proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocol) and is currently pending before the Commission in Docket No. RM14-13-000. *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards COM-001-2 and COM-002-4*, Docket No. RM14-13-000 (May 14, 2014). On September 18, 2014, the Commission issued a Notice of Proposed Rulemaking proposing to adopt the proposed Reliability Standards and new proposed definitions (including Operating Instruction), as well as the implementation plans, VRFs, and VSLs for the proposed Reliability Standards.

Model.[34] As noted above, the definition of Real-time Assessments has been modified to include additional inputs to improve situational awareness.

The proposed TOP Reliability Standards also include clear requirements for monitoring system conditions that support completion of Real-time Assessments and align with similar requirements in the currently effective IRO Reliability Standards. Specifically, proposed Reliability Standard TOP-001-3 requires, among other things, Transmission Operators and Balancing Authorities to monitor Facilities and status indications necessary to operate within SOLs and support Interconnection frequency.

d) Operations Planning and Outage Coordination

The proposed Reliability Standards also improve upon operational planning requirements for Reliability Coordinators and Transmission Operators. Proposed Reliability Standards IRO-008-2 and TOP-002-4 contain requirements for performing day-ahead studies and developing plans to operate within operating limits. Certain operational planning requirements are applicable to the Balancing Authorities as well, as discussed below. Further, the revised definition for Operational Planning Analysis incorporates recommendations from the Southwest Outage Report that are designed to address operations planning shortfalls with the potential to cause repeat occurrences of similar events, as further described in Exhibit F. For example, the revised definition of Operational Planning Analysis includes use of external system data such as transmission or generation outages, interchange prediction, and projected system conditions to improve the scope, accuracy, and quality of the analysis.

[34] NERC Functional Model at page 38. The Transmission Operator and Reliability Coordinator have similar roles with respect to transmission operations, but different scopes.

Operations planning relies on timely and accurate information of transmission and generation outages. Consequently, the standard drafting team developed proposed Reliability Standard IRO-017-1 to address the coordination of outages in advance. Proposed Reliability Standard IRO-017-1 establishes operational planning requirements for each Reliability Coordinator to implement an outage coordination process for its area that will identify and resolve issues with the potential to impact reliable operations. Proposed Reliability Standard IRO-017-1 thus addresses a reliability gap identified in the IERP Report and the Southwest Outage Report.

e) Operational Reliability Data

The proposed Reliability Standards establish clear requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations. Effective operations planning and accurate assessment of system conditions in real-time rely on complete, current, and timely data and information. Specifically, proposed TOP-003-1 establishes requirements for Transmission Operators and Balancing Authorities to specify the data and information needed to perform their reliability functions, and obligates entities to provide the data according to prescribed formats and protocols. In doing so, proposed TOP-003-1 is applying the Commission-approved approach used for Reliability Coordinators in IRO-010-1a to improve the flow of operational reliability data needed by Transmission Operators and Balancing Authorities in a consistent manner.

B. Proposed Reliability Standards and Definitions

1. <u>Proposed Definitions</u>

NERC submits for Commission approval two revised definitions for inclusion in the NERC Glossary: (i) Real-time Assessment, and (ii) Operational Planning Analysis. The additional specificity reflected in the proposed definitions addresses concerns raised in the TOP/IRO NOPR and recommendations in the Southwest Outage Report, as discussed below. The revisions in the proposed definitions are intended to make sure that Operational Planning Analyses and Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness for next-day planning and real-time operations, respectively. The current and proposed definitions of Real-time Assessment and Operational Planning Analysis are provided below.

a) "Real-time Assessment"

The term "Real-time Assessment" is used in the following proposed Reliability Standards: TOP-001-3; TOP-003-3; IRO-002-4; IRO-008-2; IRO-010-2; and IRO-014-3. The term "Real-time Assessment" is currently defined in the NERC Glossary as "[a]n examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." The proposed definition of "Real-time Assessment" is:

> An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The proposed definition adds additional detail and clarity on the data or inputs that must be evaluated in a Real-time Assessment. The proposed definition will lead to improved assessments, and, in turn, more reliable operations. The proposed definition incorporates the defined term "Contingency" to add clarity regarding the existing and expected system conditions that are examined in a Real-time Assessment. "Contingency" is defined in the NERC Glossary as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." The proposed definition also includes additional specificity regarding the various inputs for the assessment and how that information may be provided such as through third-party services. The use of third-party services may provide smaller entities an efficient method for complying with the requirements. The additional specificity in the proposed definition ensures that assessments contain sufficient details to result in an appropriate level of situational awareness.

b) "Operational Planning Analysis"

The proposed definition of "Operational Planning Analysis" is used in the following proposed Reliability Standards: TOP-002-4; TOP-003-3; IRO-002-4; IRO-008-2; IRO-010-2; and IRO-014-3. The term "Operational Planning Analysis" is defined in the NERC Glossary as follows:

> An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

The proposed definition of Operational Planning Analysis is:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

As with the definition of "Real-time Assessment," the proposed definition for Operational Planning Analysis incorporates the defined term "Contingency" to add clarity regarding the existing and expected system conditions examined in an Operational Planning Analysis, which are undefined in the current definition. The proposed definition also includes additional specificity regarding the various inputs for the analysis and how that information may be provided such as through third-party services, which may provide smaller entities an efficient method for complying with the requirements. The proposed definition removes the language specifying that the Operational Planning Analysis may be performed "either a day ahead or as much as 12 months ahead." The standard drafting team concluded that the time-frame was unnecessary for the reliability objective, which is to obtain an evaluation of projected system conditions for next-day operations based on specified inputs.

c) "Operating Instruction"

The NERC Glossary term "Operating Instruction", which is currently pending Commission approval in Docket No. RM14-13-000, is used in proposed Reliability Standards TOP-001-3 and IRO-001-4.[35] The propose definition for the term "Operating Instruction" is as follows:

> A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

As used in proposed Reliability Standard TOP-001-3, an Operating Instruction is the means by which a Transmission Operator directs entities to act to address the reliability of its Transmission Operator Area. Similarly, as used in proposed Reliability Standard, IRO-001-4, an Operating Instruction is the means by which a Reliability Coordinator directs entities to act to address the reliability of its Reliability Coordinator Area. It replaces the terms "directive" and "reliability directive" used in currently effective Reliability Standards TOP-001-1a and IRO-001-1.1.

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[35] The definition for "Operating Instruction" was developed and submitted for Commission approval along with the proposed Reliability Standard COM-002-4 (Operating Personnel Communications Protocols). As noted above, on September 18, 2014, the Commission issued a Notice of Proposed Rulemaking proposing to adopt the proposed Reliability Standards and new proposed definitions (including Operating Instruction), as well as the implementation plans, VRFs, and VSLs for the proposed Reliability Standards.

By focusing on commands that “change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System,” the definition does not attempt to differentiate between commands given in an Emergency condition or a non-Emergency condition. Further, as explained in the COM-001-2 and COM-002-4 petition, a “command,” as used in the proposed definition, purposely does not specify whether the coverage is restricted to oral or written commands. Rather, the proposed Requirements in COM-002-4 specify protocols using the qualifiers “oral” and “written” in the Requirements themselves. As a result, where used in the proposed TOP and IRO Reliability Standards, “Operating Instruction” carries the broader meaning, which captures both. The proposed definition also includes a clarifying note in parentheses that general discussions are not considered Operating Instructions.

2. Proposed Reliability Standards

a) Proposed Reliability Standard TOP-001-3 (Transmission Operations)

Proposed Reliability Standard TOP-001-3 (Transmission Operations) contains twenty requirements relating to transmission operations. As shown in Exhibit D, proposed Reliability Standard TOP-001-3 replaces relevant requirements from TOP-001-1a (Reliability Responsibilities and Authorities) and other currently effective TOP and IRO Reliability Standards proposed for retirement. The purpose of proposed Reliability Standard TOP-001-3 is to prevent instability, uncontrolled separation, or Cascading outages that adversely affect the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences. The proposed standard achieves this reliability goal by providing appropriate entities with the authority to take actions, or direct the actions of others, to maintain reliability during Real-time operations. It includes Real-time monitoring and Real-time assessment requirements to preserve reliability and ensure that applicable entities identify and address SOL exceedances. The proposed Reliability

Standard also requires entities to communicate with each other regarding issues that could affect transmission operations. The proposed Reliability Standard applies to Balancing Authorities, Transmission Operators, Generator Operators, and Distribution Providers. The following is a description of each of the requirements in TOP-001-3.

Requirements R1 and R2 require each Transmission Operator (Requirement R1) and Balancing Authority (Requirement R2) to act to address the reliability of its area through its own actions or by issuing Operating Instructions. These requirements establishes an explicit, affirmative obligation to act. In contrast, as noted by the IERP, the obligation to act in currently effective Reliability Standard TOP-001-1a is only an implied requirement.

Requirement R3 provides that each Balancing Authority, Generator Operator, and Distribution Provider must comply with each Operating Instruction issued by its Transmission Operator(s), unless doing so would violate safety, equipment, regulatory, or statutory requirements or the action cannot be physically implemented.

Requirement R4 provides that each Balancing Authority, Generator Operator, or Distribution Provider must notify the Transmission Operator if it is unable to comply with the Transmission Operator's Operating Instruction.

Requirements R5 requires that each Transmission Operator, Generator Operator, and Distribution Provider comply with each Operating Instruction issued by its Balancing Authority, unless it cannot physically implemented the action or it would violate safety, equipment, regulatory, or statutory requirements.

Requirement R6 requires each Transmission Operator, Generator Operator, and Distribution Provider to inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.[36]

Requirement R7 provides that each Transmission Operator must assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless doing so would violate safety, equipment, regulatory, or statutory requirements or such assistance cannot be physically implemented. The proposed requirement creates a clear obligation for a Transmission Operator to provide assistance within its capability (i.e. "if requested and able"), and maintains the implicit obligation that the requesting Transmission Operator is also taking similar action (i.e. "has implemented its comparable emergency procedures").

Requirement R8 provides that each Transmission Operator must inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of the Transmission Operator's actual or expected operations that result in, or could result in, an Emergency.

Requirements R9, R16, and R17 address outage coordination of monitoring and control equipment. Proposed Requirement R9 provides that each Balancing Authority and Transmission Operator must notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels

[36] The responsibility of Reliability Coordinators to act or direct others to act is addressed in proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities).

between the affected entities. Proposed Requirement R9 includes additional terms, as described in Section IV.C below in response to the Southwest Outage Report Recommendation #15. Proposed Requirements R16 and R17 provide that each Transmission Operator (Requirement R16) and each Balancing Authority (Requirement R17) must provide its System Operators with the authority to approve planned outages and maintenance.

Requirement R10 addresses Transmission Operator monitoring obligations to help ensure that Transmission Operators have the necessary situational awareness to maintain reliable operations. The proposed requirement is derived from currently effective Reliability Standard IRO-003-2, Requirement R1, which covers the monitoring obligations of Reliability Coordinators. Requirement R10 provides that each Transmission Operator must take certain steps for determining SOL exceedances within its Transmission Operator Area. Specifically, within its area, each Transmission Operator must monitor Facilities and the status of Special Protection Systems. Outside its area, the Transmission Operator must obtain and use status, voltages, and flow data for Facilities and the status of Special Protection Systems. Requirement R10 addresses the Commission's concerns that the Pending TOP/IRO Standards did not have sufficient requirements for real-time monitoring.[37]

Requirement R11 is the equivalent of Requirement R10 for Balancing Authorities. Under Requirement R11, each Balancing Authority is required to monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

[37] TOP/IRO NOPR at P 60.

Requirement R12 provides that each Transmission Operator must not operate outside of any identified IROL for a continuous duration exceeding its associated IROL T_v.

Requirement R13 provides that each Transmission Operator must ensure that a Real-time Assessment is performed at least once every 30 minutes. This proposed requirement is derived from Reliability Standard IRO-008-1, Requirement R2, which applies to Reliability Coordinators, and will significantly improve situational awareness.[38]

Requirement R14 provides that each Transmission Operator must initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.[39] As discussed below, proposed Reliability Standard TOP-002-4, Requirement R3 requires Transmission Operators to have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances.

Requirement R15 provides that each Transmission Operator must inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded.

Requirement R18 provides that each Transmission Operator must operate to the most limiting parameter in instances where there is a difference in SOLs. As shown in Exhibit D, this Requirement is from currently effective IRO-005-3.1a, Requirement R10. The phrase "derived limits" in IRO-005-3.1a R10 is replaced with "SOLs" for clarity and consistency.

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[38] As described below, proposed Reliability Standard TOP-002-4, Requirement R2 requires Transmission Operators to have an Operating Plan for next-day operations. It is appropriate for an Operating Plan to contain guidance for performing Real-time Assessments with detailed instructions and timing requirements to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

[39] An "Operating Plan" is defined in the NERC Glossary as:

> A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Requirements R19 and R20 provide that each Transmission Operator (Requirement R19) and Balancing Authority (Requirement R20) must have data exchange capabilities with the entities from which it needs data in order to maintain reliability in its area. Proposed Requirements R19 and R20 are consistent with proposed Reliability Standard IRO-002-4, Requirement R1, which provides that each Reliability Coordinator must have data exchange capabilities with its Balancing Authorities, Transmission Operators, and other entities it deems necessary. These data exchange capabilities are required to support the data specifications required in proposed Reliability Standard TOP-003-3, as discussed below.

b) Proposed Reliability Standard TOP-002-4 (Operations Planning)

Proposed Reliability Standard TOP-002-4 (Operations Planning) contains seven requirements relating to operations planning for Transmission Operators and Balancing Authorities, replacing relevant requirements from Reliability Standard TOP-002-1b (Normal Operations Planning) and other TOP and IRO Reliability Standards proposed for retirement, as shown in Exhibit D hereto. The purpose of proposed Reliability Standard TOP-002-4 is to ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits. Specifically, the proposed standard addresses next-day planning and operations and provide for the necessary notifications and coordination between various functional entities. The revised definition of Operational Planning Analysis is an integral component of proposed TOP-002-4 and specifies the scope and inputs required for next-day analyses. The proposed standard also improves coordination of next-day operations by requiring Transmission Operators and Balancing Authorities to provide Operating Plans to their Reliability Coordinators. Proposed Requirements R1 through R3 and R6 apply to Transmission Operators, and proposed Requirements R4, R5, and R7 apply to Balancing Authorities. The following is a description of each of the requirements in TOP-002-4.

Requirement R1 requires each Transmission Operator to have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs.

Requirement R2 requires each Transmission Operator to have an Operating Plan (or Plans) for next-day operations to address potential SOL exceedances identified in the Operational Planning Analysis performed pursuant to Requirement R1.

Requirement R4 requires each Balancing Authority to have an Operating Plan (or Plans) for the next day that address four items: (i) expected generation resource commitment and dispatch; (ii) interchange scheduling; (iii) demand patterns; and (iv) capacity and energy reserve requirements, including deliverability capability.

Requirements R3 and R5 require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R5) to notify the entities identified in their Operating Plan as to their roles in that plan.

Requirements R6 and R7 require each Transmission Operator (Requirement R6) and Balancing Authority (Requirement R7) to provide its plan to its Reliability Coordinator.

c) Proposed Reliability Standard TOP-003-3 (Operational Reliability Data)

Proposed Reliability Standard TOP-003-3 (Operational Reliability Data) establishes requirements for the provision of information and data needed by the Transmission Operator and Balancing Authority for reliable operations, replacing relevant requirements from Reliability Standard TOP-003-1, as shown in Exhibit D. The purpose of proposed Reliability Standard TOP-003-3 is to ensure that Transmission Operators and Balancing Authorities have the data needed to fulfill their operational and planning responsibilities. Proposed TOP-003-3 is derived from the

Commission-approved approach for Reliability Coordinators in Reliability Standard IRO-010-1a to improve the flow of operational reliability data needed by Transmission Operators and Balancing Authorities.[40]

The proposed Reliability Standard consists of five Requirements, including requirements for Balancing Authorities and Transmission Operators to maintain and distribute to relevant entities data specifications needed to perform various analyses and assessments. The proposed Reliability Standard also requires entities receiving data specifications to respond according to mutually agreed upon parameters. The following is a description of each of the Requirements in TOP-003-3.

Requirement R1 requires each Transmission Operator to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include, but is not limited to:

- a list of data and information needed to support these analyses, monitoring, and assessments;
- provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirement R2 requires each Balancing Authority to maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification must include:

40 Proposed Reliability Standard IRO-010-2 replaces Reliability Standard IRO-010-1a and contains the data specification requirements for Reliability Coordinators.

- a list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring;
- provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent (i.e., recipient) is to provide the indicated data.

Requirements R3 and R4 require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R4) to distribute its data specification to the entities that have the necessary data.

Requirement R5 requires each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification using: (i) a mutually agreeable format; (ii) a mutually agreeable process for resolving data conflicts; and (iii) a mutually agreeable security protocol.

Data specification and collection for Reliability Coordinators is addressed in proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection), discussed below.

d) Proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities)

Proposed Reliability Standard IRO-001-4 (Reliability Coordination – Responsibilities) contains requirements relating to the Reliability Coordinator's overall responsibility for reliable operation within the Reliability Coordinator Area. The purpose of the proposed Reliability Standard is to establish the responsibility of Reliability Coordinators to act or direct others to act to address the reliability of the Reliability Coordinator Area. The proposed Reliability Standard is applicable to Reliability Coordinators, Transmission Operators, Balancing Authorities, Generator Operators, and Distribution Providers, which is consistent with the entities that are listed as receiving instructions from the Reliability Coordinator in the NERC functional model. The Transmission Service Provider is not an applicable entity as it does not perform an operating reliability function under the direction of the Reliability Coordinator, as described in the NERC Functional Model.

The proposed Reliability Standard contains the following three requirements:

- *Requirement R1* provides that each Reliability Coordinator must act to address the reliability of its Reliability Coordinator Area through direct actions or by issuing Operating Instructions.

- *Requirement R2* provides that each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider must comply with its Reliability Coordinator's Operating Instructions unless compliance cannot be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements.

- *Requirement R3* provides that a Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider informs the Reliability Coordinator that it is unable to perform an Operating Instruction issued by its Reliability Coordinator.

e) Proposed Reliability Standard IRO-002-4 (Reliability Coordination – Monitoring and Analysis)

Proposed Reliability Standard IRO-002-4 (Reliability Coordination – Monitoring and Analysis) contains requirements relating to capabilities for monitoring and analysis of Real-time operating data. The purpose of the proposed Reliability Standard is to provide System Operators with the capabilities necessary to monitor and analyze data needed to perform reliability functions.

The proposed Reliability Standard consists of the following four requirements:

- *Requirement R1* requires each Reliability Coordinator to have data exchange capabilities with its Balancing Authorities, Transmission Operators, and other entities as it deems necessary, for it to perform the Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

- *Requirement R2* provides that each Reliability Coordinator must provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring, and analysis capabilities.

- *Requirement R3* provides that each Reliability Coordinator must monitor Facilities, the status of Special Protection Systems, and non-Bulk Electric System facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to identify any SOL or IROL exceedances within its Reliability Coordinator Area.

- *Requirement R4* provides that each Reliability Coordinator must have monitoring systems that provide information used by the Reliability Coordinator's operating personnel, with particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

f) Proposed Reliability Standard IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments)

Proposed Reliability Standard IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments) contains requirements for Reliability Coordinators to conduct next-day analyses and assessments of operating conditions in Real-time to help prevent instability, uncontrolled separation, or Cascading. The proposed definitions of Operational Planning Analysis and Real-time Assessment are integral components of proposed IRO-008-2 as they specify the scope and inputs for next-day analysis and real-time assessments of operating conditions in Real-time. Furthermore, proposed IRO-008-2 enhances next-day operations planning by specifying requirements for coordination of the Reliability Coordinator's Operating Plan to address potential SOL and IROL exceedances.

The proposed Reliability Standard consists of the following six requirements, designed to ensure that Reliability Coordinators perform analyses to identify potential or actual SOL or IROL exceedances and that such exceedances are addressed in a coordinated fashion:

- *Requirement R1* provides that each Reliability Coordinator must perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed SOLs and IROLs within its Wide Area.

- *Requirement R2* provides that each Reliability Coordinator must have a coordinated Operating Plan for next-day operations to address potential SOL and IROLs exceedances identified as a result of its Operating Planning Analysis performed pursuant to Requirement R1. The coordinated Operating Plan must consider the Operating Plans provided by its

Transmission Operators and Balancing Authorities pursuant to Requirements R6 and R7 of proposed Reliability Standard TOP-002-4.

- *Requirement R3* provides that each Reliability Coordinator must notify impacted entities identified in its Requirement R2 Operating Plan as to their role in the plan.
- *Requirement R4* provides that each Reliability Coordinator must ensure that a Real-time Assessment is performed at least once every 30 minutes.
- *Requirement R5* provides that each Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.
- *Requirement R6* provides that each Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated.

g) Proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection)

Proposed Reliability Standard IRO-010-2 (Reliability Coordinator Data Specification and Collection) provides a mechanism for the Reliability Coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or Cascading outages. Proposed Reliability Standard IRO-010-2 reflects recommendations from Southwest Outage Report, including more clearly identifying necessary data and information to be included in the Reliability Coordinator's data specification.

The proposed Reliability Standard consists of the following three requirements:

- *Requirement R1* provides that the Reliability Coordinator must maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification must include:
    - a list of data and information necessary to support Reliability Coordinator Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, including non-Bulk Electric System data and external network data, as deemed necessary by the Reliability Coordinator;

- provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability;
- a periodicity for providing data; and
- the deadline by which the respondent is to provide the indicated data.

- *Requirement R2* provides that the Reliability Coordinator must distribute its data specification to entities that have the required data.
- *Requirement R3* provides that each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification must satisfy the obligations of the documented specifications using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

h) Proposed Reliability Standard IRO-014-3 (Coordination Among Reliability Coordinators)

Proposed Reliability Standard IRO-014-3 (Coordination Among Reliability Coordinators) contains requirements for coordination for interconnected operations at the Reliability Coordinator level. The purpose of the proposed Reliability Standard is to ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely affect other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

The proposed Reliability Standard consists of the following seven requirements:

- *Requirement R1* requires each Reliability Coordinator to have and implement Operating Procedures, Processes, or Plans for activities that require notification or coordination of actions that may affect adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Processes, or Plans must include, at a minimum: (i) criteria and processes for notifications; (ii) energy and capacity shortages; (iii) control of voltage, including the coordination of reactive resources; (iv) exchange of information, including planned and unplanned outage information to support Operational Planning Analyses and Real-time Assessments; and (v) provisions for periodic communications to support reliable operations.
- *Requirement R2* requires each Reliability Coordinator to maintain its Operating Procedures, Processes, or Plans through annual reviews and updates, with no more than 15 months passing between reviews. For each update, the Reliability Coordinator is required to obtain written agreement from the other Reliability Coordinators required to take the indicated action and distribute the Operating Procedures, Process, or Plans within 30 days of an update.

- *Requirement R3* requires each Reliability Coordinator to notify other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

- *Requirement R4* specifies that, in the event Reliability Coordinators disagree on the existence of an Emergency, each impacted Reliability Coordinator must operate as though an Emergency exists.

- *Requirement R5* provides that each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area must develop an action plan to resolve the Emergency.

- *Requirement R6* provides that each impacted Reliability Coordinator must implement the action plan developed by the Reliability Coordinator that identifies the Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

- Requirement R7 requires each Reliability Coordinator to assist other Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its Emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. The proposed requirement creates an affirmative obligation for the Reliability Coordinator to provide assistance within its capability (i.e. "if requested and able"), and maintains the implicit obligation that the requesting Reliability Coordinator is also taking similar action (i.e. 'has implemented its emergency procedures").

i) Proposed Reliability Standard IRO-017-1 (Outage Coordination)

Proposed Reliability Standard IRO-017-1 (Outage Coordination) is a new Reliability Standard designed to ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.[41] Transmission Planning and Operations Planning involve different functional entities per the NERC Functional Model. Furthermore, these two types of planning involve different objectives, information, timeframes, and processes. The requirements in the proposed Reliability Standard, which span both time horizons, provide the necessary requirements for effective coordination of planned outages to support reliable operations.

[41] The Operations Planning time horizon refers to "operating and resource plans from day-ahead up to and including seasonal." *See* Time Horizons, *available at* http://www.nerc.com/files/Time_Horizons.pdf. The term Near-Term Transmission Planning Horizon is defined in the NERC Glossary as "[t]he transmission planning period that covers Year One through five."

Proposed Reliability Standard IRO-017-1 consists of the following four requirements to address planned outage coordination concerns.

- *Requirement R1* provides that each Reliability Coordinator must develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. This process must:
    - identify applicable roles and reporting responsibilities, including development and communication of outage schedules and assignment of coordination responsibilities for outage schedules between Transmission Operators and Balancing Authorities;
    - specify outage submission timing requirements;
    - define the process to evaluate the impact of Transmission and generation outages with the Reliability Coordinator's Wide Area; and
    - define the process to coordinate the resolution of identified outage conflicts with Transmission Operators and Balancing Authorities, as well as other Reliability Coordinators.
- *Requirement R2* provides that each Transmission Operator and Balancing Authority must perform the functions specified in its Reliability Coordinator's outage coordination process.
- Requirement R3 provides that each Planning Coordinator and Transmission Planner must provide its Planning Assessment to impacted Reliability Coordinators.[42] Planning Coordinators and Transmission Planners are required to develop Planning Assessments under the currently effective Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).
- Requirement R4 requires each Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

C. Consideration of the Southwest Outage Report Recommendations

The following section discusses the manner in which the proposed Reliability Standards address the recommendations of the Southwest Outage Report. On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading

[42] Planning Assessment is defined in the NERC Glossary as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

outages and leaving approximately 2.7 million customers without power ("2011 Southwest Outage"). The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers in the region losing power, some for up to 12 hours.[43]

Following the 2011 Southwest Outage, NERC and FERC conducted a joint investigation. The investigation concluded that the cause of the disturbance stemmed primarily from weaknesses in operations planning and real-time situational awareness, which, if conducted properly, would have allowed system operators to proactively operate the system in a secure state during normal system conditions and to restore the system to a secure state as soon as possible.[44]

On April 27, 2012, FERC and NERC issued the Southwest Outage Report, outlining the investigators' findings and making recommendations for reliability improvements. The Southwest Outage Report made twenty-seven (27) findings and associated recommendations applicable mostly to Transmission Operators, Balancing Authorities, and Reliability Coordinators. These findings and recommendations addressed the lack of adequate operations planning and real-time situational awareness of contingency conditions, as well as other factors that contributed to the 2011 Southwest Outage.[45] The Southwest Outage Report findings are divided into eight

43 Southwest Outage Report at 1.

44 *Id*. at 5.

45 The Southwest Outage Report concluded that several other factors contributed to the 2011 Southwest Outage. For example, the Reliability Coordinator and the affected entities did not consistently recognize the adverse impact that sub-100 kV facilities can have on the Bulk-Power System reliability. Furthermore, there were significant issues with Protection System settings. *See* Southwest Outage Report pp. 63-110 and Appendix B: Table of Findings and Recommendations.

categories, [46] and each category lists specific reliability issues identified during the joint investigation.

As part of Project 2014-03, the standard drafting team considered the Southwest Outage Report findings and recommendations applicable to Transmission Operators, Balancing Authorities and Reliability Coordinators, and addressed these recommendations in the language of the proposed Reliability Standards.[47] Several of the findings and recommendations were outside the scope of Project 2014-03 either fully, or partially, as discussed in this section of the petition.[48] Below is a short description of each applicable finding and recommendation identified in the Southwest Outage Report,[49] and an explanation of how the proposed Reliability Standards address the reliability issues identified following the 2011 Southwest Outage. The full listing of the recommendations and mapping to the proposed TOP and IRO Reliability Standards is provided in Exhibit F. A summary of the findings and recommendations is available in Appendix B of the Southwest Outage Report.

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[46] The eight categories of findings are: next-day planning, seasonal planning, near-and long-term planning, situational awareness, consideration of Bulk Electric System equipment, Interchange System Operating Limits (IROLs) derivations, Protection Systems, and angular separation. *See* Southwest Outage Report, Appendix B.

[47] *See* Exhibit F Mapping of Revised TOP and IRO Reliability Standards to Address 2012 Southwest Outage Report Recommendations ("Southwest Outage Recommendation Mapping Document"). Several of the Southwest Outage Report recommendations were specific to the particular facts and circumstances of the 2011 Southwest Outage, and were not addressed in the Southwest Outage Recommendation Mapping Document. The Southwest Outage Report identified weaknesses in WECC seasonal planning, but the standard drafting team determined that these weaknesses should not become prescriptive requirements for all Reliability Coordinator areas.

[48] *Id.*

[49] *See* Southwest Outage Report, Appendix B for a list of all findings and recommendations included in the Southwest Outage Recommendation Mapping Document and this petition.

1. <u>Operations Planning</u>

Eight findings in the Southwest Outage Report relate to operations planning.[50] The Southwest Outage Report's next-day and seasonal planning recommendations fall within this category and were considered together by the standard drafting team.

As described more fully below, the Southwest Outage Report recommendations related to operations planning are addressed generally by proposed Reliability Standards IRO-017-1, TOP-002-4 and IRO-008-2. Proposed Reliability Standard IRO-017-1 addresses the outage coordination concerns identified in the Southwest Outage Report, as its purpose is to ensure that outages are properly coordinated in the Operations Planning Time Horizon and Near-Term Transmission Planning Horizon. Outage coordination in the Operations Planning Time Horizon supports the needs of the Transmission Operators and the Reliability Coordinators to plan for reliable next-day operations, as required by the proposed TOP-002-4 and IRO-008-2. Specific considerations related to each finding are included below.

Finding #1: Failure to Conduct and Share Next-Day Studies

The Southwest Outage Report concluded that not all of the affected Transmission Operators conduct next-day studies or share their studies with the neighboring Transmission Operator and the Reliability Coordinator. Accordingly, recommendation #1 suggested that all Transmission Operators should conduct next-day studies and share the results with neighboring Transmission Operators and the Reliability Coordinator (before the next day). This measure was proposed to ensure that all contingencies that could affect the Bulk-Power System are studied.

[50] The standard drafting team referenced the definition of "Operations Planning Time Horizon" to group items. This definition includes "operating and resource plans from day-ahead up to and including seasonal."

The proposed language of TOP-002-4, Requirements R1, R3, and R6 directly addresses this recommendation by requiring Transmission Operators to conduct next-day studies (Requirement R1), share the results of the studies with the registered entities identified in the Operating Plan(s) (Requirement R3), and provide the results to the Reliability Coordinator (Requirement R6).

Finding #2: Lack of Updated External Networks in Next-Day Study Models

The Southwest Outage Report determined that when conducting next-day studies, some affected Transmission Operators used models that do not reflect next-day operating conditions external to their systems. Recommendation #2 stated that Transmission Operators and Balancing Authorities update their studies to reflect these conditions. Such external operating conditions include generation and transmission outages and scheduled Interchanges.

Proposed Reliability Standards TOP-002-4, Requirement R1 and TOP-003-3 Requirement R1, Part 1.1, and the proposed definition of Operational Planning Analysis address this particular reliability concern. Specifically, TOP-002-4 Requirement R1 requires the Transmission Operators to have Operational Planning Analysis for the next day, which under the proposed definition includes external operating conditions like Interchange data, transmission and generator outages, and identified equipment limitations. In addition, proposed Reliability Standard TOP-003-3 Requirement R1, Part 1.1 requires Transmission Operators to maintain a documented specification for the data they need to support Operational Planning Analyses, including external network data.

Furthermore, recommendation #2 suggested that Transmission Operators and Balancing Authorities should take the necessary steps to allow free exchange of next-day operational data between operating entities. TOP-003-3 Requirements R1, R2 and R5 address this reliability issue. Requirement R1 directs Transmission Operators to maintain data specification for the data necessary to perform Operational Planning Analysis, and Requirement R2 establishes a similar obligation for Balancing Authorities. Requirement R5 requires Transmission Operators, Balancing Authorities, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Owners, and Distribution Providers to satisfy any requests for information included in the proposed Reliability Standard that are necessary for completion of the required Operational Planning Analysis.

The same recommendation also concluded that the Reliability Coordinators should review the procedures for coordinating next-day studies within their region, ensure adequate data exchange among Balancing Authorities and Transmission Operators, and facilitate the next-day studies conducted by Balancing Authorities and Transmission Operators. This issue is addressed in proposed IRO-008-2 R2, which directs Reliability Coordinators to have coordinated Operating Plans(s) for next-day operations. These coordinated Operating Plans aim to timely and adequately address reliability issues identified in the next-day Operational Planning Analysis.

Finding #3: Sub-100 kV Facilities not Adequately Considered in Next-Day Studies

In the Southwest Outage Report, NERC and FERC staff determined that in conducting next-day studies, some Transmission Operators do not adequately consider lower-voltage facilities below 100 kV. Recommendation #3 stated that Transmission Operators and Reliability Coordinators should ensure their next-day studies include all internal and external facilities (including those below 100 kV) that can affect Bulk-Power System reliability. Proposed TOP-003-3 R1.1 and IRO-010-2 R1.1 address this by specifically requiring Transmission Operators and Reliability Coordinators to incorporate any non-Bulk Electric System data deemed necessary into their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Finding #4: Flawed Process for Estimating Scheduled Interchanges

During the 2011 Southwest Outage investigation, NERC and FERC staff determined that the Reliability Coordinator process for estimating scheduled Interchanges was not adequate to ensure that such values were accurately reflected in the Reliability Coordinator's next-day studies. Recommendation #4 suggested that the Reliability Coordinator involved in the event should improve its process for predicting Interchanges in the day-ahead timeframe. In the proposed definition of Operational Planning Analysis, Interchange data is an included input of next-day studies, which addresses this recommendation.

Finding #5: Lack of Coordination in Seasonal Planning Process

The Southwest Outage Report concluded that due to a lack of coordination in the seasonal planning process in the Western Electricity Coordinating Council ("WECC") region, Transmission Operators may fail to identify contingencies in one subregion that could affect other Transmission Operators in the same or another subregion. Recommendation #5 addresses this issue by recommending that the individual Transmission Operators should conduct a full contingency seasonal analysis to identify contingencies outside their own systems and share the analysis with the other affected Transmission Operators.[51]

Proposed Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3 address coordination of operational planning among Transmission Operators by requiring Transmission Operators to gather external data deemed necessary to perform analysis and share the results of the studies with the affected entities. Furthermore, proposed Reliability Standard IRO-017-1 requires Reliability Coordinators to establish an outage coordination process that will

[51] This recommendation also included language related to actions of the WECC Regional Entity. This section of the recommendation was not considered by the standard drafting because it is not applicable to Reliability Coordinators, Transmission Operators and Balancing Authorities and falls outside the scope of Project 2014-03.

identify and resolve transmission and generation planned outage issues in the Operations Planning Time Horizon, which includes next-day and seasonal planning periods that have the potential to impact the Reliability Coordinator's wide-area.

Finding #6: External and Lower-Voltage Facilities not Adequately Considered in Seasonal Planning Process

The Southwest Outage Report concluded in recommendation #6 that the focus of Transmission Operator seasonal planning should be expanded to include external facilities and internal and external sub-100 kV facilities that affect Bulk-Power System reliability. This reliability concern is addressed in TOP-003-3, Requirement R1, which requires Transmission Operators to obtain external network and sub-100 kV data deemed necessary for use in Operational Planning Analyses. Additionally, the outage coordination process established by Reliability Coordinators, as required by proposed IRO-017-1, must specifically address wide-area issues. In this manner, the proposed Reliability Standards collectively ensure that the scope of operations planning from day-ahead up to and including seasonal planning extends beyond the individual Transmission Operator Area and is coordinated across the Reliability Coordinator Area. Furthermore, proposed Reliability Standard IRO-017-1, Requirement R1 specifies that the Reliability Coordinator's outage coordination process must include a process for resolving planned outage conflicts with other Reliability Coordinators.

Finding #7: Failure to Study Multiple Load Levels

The Southwest Outage Report determined that Transmission Operators in WECC do not always conduct their individual planning studies based on multiple base cases, and as a result, some contingencies could be missed and excluded from the studies. FERC and NERC staff suggested in recommendation #7 that Transmission Operators include in their seasonal studies multiple base cases and generation maintenance outages, as well as dispatch scenarios during high-load shoulder periods. The standard drafting team addressed this issue by including a broader definition of Operational Planning Analysis, under which projected system conditions such as load forecasts and generation output levels must be considered by Transmission Operators and Reliability Coordinators. Such projected system conditions would include generator outages and high-load periods. Additionally, the outage coordination process established by Reliability Coordinators as required by proposed IRO-017-1 must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area. The Reliability Coordinator's outage coordination process covers the Operations Planning Time Horizon, which spans from day-ahead up to and including seasonal planning.

Finding #8: Not Sharing Overload Relay Trip Setting

Recommendation #8 of the Southwest Outage Report recommended that Transmission Operators include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that affect the Bulk-Power System. This reliability concern is addressed in proposed Reliability Standards TOP-003-3, Requirement R1 and TOP-002-4, Requirement R3, and in the associated definition of Operational Planning Analysis. TOP-003-3, Requirement R1 requires Transmission Operators to maintain provisions for notification of current Protection System and Special Protection System status or degradation that affects system reliability. The proposed Reliability Standard TOP-002-4, Requirement R3 requires sharing of the study results among the Transmission Operators. Furthermore, the definition of Operational Planning Analysis explicitly requires that Protection Systems be included in the pre-and-post contingency studies.

Additionally, the Reliability Coordinators must specifically define a process to evaluate the impact of transmission and generation planned outages within the wide-area as required by proposed IRO-017-1. This process would include relevant system inputs necessary to evaluate the impact of transmission and generation planned outages on the reliable operation of the Bulk Power System. The Reliability Coordinator's outage coordination process covers the Operations Planning Time Horizon, which spans from day-ahead up to and including seasonal planning.

2. Near-and-long term planning

Finding #9: Gaps in Planning Process

Recommendation #9 of the Southwest Outage Report recommended that Transmission Operators[52] develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all Protection Systems, including remedial action schemes (RASs), Safety Nets (such as the San Onofre Nuclear Generating Station (SONGS) separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on Bulk-Power System reliability. This reliability concern is addressed in proposed Reliability Standard TOP-003-3, Requirement R1, Part 1.1 and 1.2 and the proposed definition of Operational Planning Analysis, as discussed above.

3. Situational Awareness

Finding #11: Lack of Real-Time External Visibility

NERC and FERC staff concluded in the Southwest Outage Report that Transmission Operators have limited real-time visibility outside their systems and lack adequate situational awareness of external contingencies. Accordingly, recommendation #11 proposed that Transmission Operators engage in more real-time data sharing and obtain sufficient data to monitor significant external facilities in real-time. Proposed Reliability Standard TOP-003-3 addresses

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[52] This recommendation is also applicable to Planning Coordinators and Transmission Planners, which fall outside the scope of Project 2014-03. Recommendation #9 includes language applicable specifically to WECC Regional Entity, which is also outside the scope of the proposed Reliability Standards. Recommendation #10 is not applicable and was not considered by the standard drafting team.

this issue by requiring Transmission Operators to include external network data in their data specifications for Operational Planning Analyses.

In addition, recommendation #11 advised that Transmission Operators review their real-time monitoring tools, such as state estimator and real-time contingency analysis ("RTCA"), to ensure that such tools reflect the critical facilities needed for the reliable operation of the Bulk Power System. The language in proposed Reliability Standard TOP-001-3, Requirement R13 addresses this reliability concern by requiring Transmission Operators to perform a Real-time Assessment at least once every 30 minutes. Furthermore, the proposed definition of Real-time Assessment includes an assessment of potential post-contingency operating conditions.

Finding #12: Inadequate Real-Time Tools

In recommendation #12, FERC and NERC staff advised that Transmission Operators should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems. Proposed Reliability Standard TOP-001-3, Requirement R13, as described in detail above, is designed to resolve this specific issue by requiring Transmission Operators to ensure a Real-time Assessment is performed at least once every 30 minutes.

Finding #13: Reliance on Post-Contingency Mitigation Plans

The Southwest Outage Report determined that post-contingency mitigation plans are not viable under all circumstances and suggested in recommendation #13 that Transmission Operators review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions to return the system to a secure state. Proposed Reliability Standards TOP-002-4, Requirement R2 and TOP-001-3, Requirement R14 resolve this issue by requiring Transmission Operators to have an Operating Plan to address SOL exceedances, and initiate the Operating Plan to mitigate an exceedance as part of its real-time monitoring or assessment.

In addition, the standard drafting team has developed a white paper on SOL definition and exceedance criteria (the "SOL White Paper"), which clarified the standard drafting team's position on establishing and exceeding SOLs, and on implementing Operating Plans to mitigate exceedances.[53] The SOL White Paper provides important linkages between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective Operating Plans to mitigate SOL exceedances.

Finally, recommendation #13 advised that as part of the review of existing operating processes and procedures, Transmission Operators should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures. This reliability concern is addressed in proposed Reliability Standard TOP-003-3, Requirement R1, and the proposed definitions of Operational Planning Analysis and Real-time Assessment, which collectively require the acquisition of Protection System data, such as relays that automatically isolate facilities, as an item to be included in the TOP studies.

> *Finding #15: Failure to Notify WECC Reliability Coordinator and the Neighboring Transmission Operators Upon Losing Real Time Contingency Analysis (RTCA) Capability*

During the 2011 Southwest Outage, at least one affected Transmission Operator lost the ability to conduct RTCA more than 30 minutes prior to, and throughout the course of the event. As a result, recommendation #15 suggested that Transmission Operators should ensure procedures

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[53] *System Operating Limit Definition and Exceedance Clarification*, White Paper (May 2014). Available at: http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_first_posting_white_paper_sol_exceedance_20140509.pdf

and training[54] are in place to notify WECC Reliability Coordinator and neighboring Transmission Operators and Balancing Authorities promptly after losing RTCA capabilities. Proposed TOP-001-3, Requirement R9, which requires Transmission Operators to notify affected registered entities of outages to monitoring and assessment capabilities, addresses this recommendation.

4. Consideration of Bulk Electric System Equipment

Designation of Bulk Electric System facilities is outside the scope of Project 2014-03. The proposed Reliability Standards incorporated non-Bulk Electric System data and facilities monitoring where necessary for the reliable operation of the Bulk Electric System, as shown below.

Finding #17: Impact of Sub-100 kV Facilities on Bulk Power System Reliability

The Southwest Outage Report determined that WECC Reliability Coordinator and affected Transmission Operators and Balancing Authorities did not consistently recognize the adverse impact sub-100 kV facilities could have on Bulk-Power System reliability. Recommendation #17 concluded that WECC, as the Reliability Coordinator, should lead other entities, including Transmission Operators and Balancing Authorities, to ensure that all facilities that can adversely impact Bulk-Power System reliability are either designated as part of the Bulk Electric System or otherwise incorporated into planning and operations studies, and actively monitored and alarmed in RTCA systems.

With respect to sub-100 kV facilities, the standard drafting team determined that any sub-100 kV elements that is necessary for reliable operation of the Bulk Electric System would be included as Bulk Electric System facilities through the exception process provided in Appendix

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54 The training issue falls outside of the scope of Project 2014-03.

5C to the NERC Rules of Procedure.[55] The exception process provides the means for Transmission Operators and Reliability Coordinators to include Elements in the Bulk Electric System that are necessary for the reliable operation of the interconnected transmission system but were not identified in the Bulk Electric System definition.[56] Accordingly, the standard drafting team concluded it is unnecessary to include non-Bulk Electric System monitoring. In addition, proposed Reliability Standard TOP-001-3, Requirement R10 requires Transmission Operators to monitor Facilities within their Transmission Operator Area, and to obtain information deemed necessary by the Transmission Operator about such Facilities located outside of the Transmission Operator Area when determining SOL exceedances.

When non-Bulk Electric Facilities have no impact on the Bulk Electric System, but are needed for completing system models, then the Commission-approved FAC-001-2, Requirement R3 addresses the issue. This Reliability Standard requires the Reliability Coordinator to include in its methodology its entire Reliability Coordinator Area and critical modeling details from other Reliability Coordinator Areas that would affect the Facility under study. In addition, the Reliability Coordinator must include details of system models used to determine SOLs.

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55 *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012), *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013); *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 143 FERC ¶ 61,231, at P 13 (2013).

56 In approving the exception process, the Commission stated:

> We believe that entities, having knowledge of their systems and the concomitant planning assessments and system impact studies, will identify an element that is necessary for reliable operation of the integrated transmission network while conducting their day-to-day operations and planning and performing studies. If the element does not fall within the definition, we expect that the entity will submit the element for inclusion through the exception process. Use of this process should ensure that the all sub-100 kV elements, as well as other facilities, necessary for the operation of the interconnected transmission network are included in an 'appropriate and consistent' manner.

Order No. 773 at P 269.

Similarly, proposed Reliability Standard IRO-002-4, Requirement R4 requires each Reliability Coordinator to monitor facilities identified as necessary within its Reliability Coordinator Area and within neighboring Reliability Coordinator Areas, and to identify any SOL exceedances and to determine any IROL exceedances.

Finally, as noted above, the proposed Reliability Standards TOP-003-3, Requirement R1 and IRO-010-2, Requirement R1 incorporate non-Bulk Electric System facilities into the data used by Transmission Operators and Reliability Coordinators to support their analysis.

5. Interconnection Reliability Operating Limit Derivations

Finding #18: Failure to Establish Valid SOLs and Identify IROLs

Recommendation #18.1 of the Southwest Outage Report advised that Reliability Coordinators study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time. Reliability Standard FAC-014-2, Requirement R1 directs the Reliability Coordinator to establish SOLs and IROLs. To address the recommendation, proposed Reliability Standard IRO-008-2, Requirement R1 further specifies that each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its wide-area. In addition, IRO-008-2, Requirement R4 requires the Reliability Coordinator to perform a Real-time Assessment of system conditions at least once every 30 minutes.

6. Protection Systems

Findings #19-#26: Related to Coordination of Special Protection Systems and Remedial Action Schemes at the Reliability Coordinator and TOP level

The standard drafting team determined that currently effective Reliability Standard PRC-001 already addresses coordination of Special Protection Systems and Remedial Action Schemes. Thus, any changes to Protection System coordination falls outside the scope of Project 2014-3.

Nevertheless, proposed Reliability Standards TOP-001-3, Requirement R10 and IRO-002-4, Requirement R4 address monitoring of Special Protection Systems and Remedial Action Schemes.[57] TOP-001-3, Requirement R10 Part 10.1 mandates Transmission Operators to monitor Facilities and the status of Special Protection Systems within their Transmission Operator areas, while Part 10.2 mandates the same actions for Facilities outside of a Transmission Operator's area.

7. <u>Angular Separation</u>

Findings #27: Phase Angle Difference Following Loss of Transmission Line

The Southwest Outage Report concluded that one of the Transmission Operators involved in the 2011 Southwest Outage did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Recommendation #27 included several possible actions to address this failure, including a suggestion that the Transmission Operators should have the tools necessary to evaluate phase angle differences following the loss of lines. Although the recommended changes related to phase angle calculation tools fall outside the scope of Project 2014-3 as it is being addressed in Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities, the proposed definition of Operational Planning Analysis and Real-time Assessment include consideration of phase angle and equipment limitations.

D. Consideration of TOP/IRO NOPR Concerns

In its TOP/IRO NOPR, the Commission expressed certain concerns regarding the Pending TOP/IRO Standards and proposed to remand those standards for further consideration in NERC's

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[57] During the development of the proposed TOP/IRO standards, the terms Remedial Action Scheme and Special Protection System were interchangeable as defined in the NERC Glossary of Terms. On February 3, 2015 NERC filed a petition for approval of revisions to the definition of "*Remedial Action Scheme*" ("RAS"), which proposes to eliminate the defined term Special Protection System. See RM15-13-000. Proposed TOP/IRO standards will be modified as necessary based on the Commission's action in response to NERC's petition in RM15-13-000.

standards development process.[58] The Commission identified "Issues to be addressed" and "Issues Requiring Clarifications." As part of Project 2014-03, the standard drafting team considered the issues raised in the TOP/IRO NOPR and designed the proposed Reliability Standards to address the Commission's concerns. This section discusses the manner in which the proposed Reliability Standards address each of the issues raised in the TOP/IRO NOPR. Additional information is provided in Exhibit G hereto.

1. <u>TOP Reliability Standards – Issues to be Addressed</u>

a. Plan and Operate Within All SOLs

The Commission expressed concern that the Pending TOP/IRO Standards lacked a requirement for Transmission Operators to analyze and operate within all SOLs.[59] Specifically, the Commission stated that while the Pending TOP/IRO Standards require Transmission Operators to plan to operate within all IROLs, they only require Transmission Operators to plan to operate within a limited subset of SOLs identified by the Transmission Operator as necessary to support reliability internal to its area.[60] The Commission maintained that this limitation would reduce system reliability and cause negative consequences external to the Transmission Operator's area.[61] The Commission also expressed the concern that deteriorating system conditions may result in an SOL rapidly degrading into an IROL. The Commission noted further that limiting the analysis to non-IROL SOLs identified internally by the Transmission Operator may "reduce system reliability because operators have less situational awareness of the system and conditions."[62]

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58 TOP/IRO NOPR at PP 42-99.

59 *Id*. at P 42.

60 *Id*.

61 *Id*. at PP 42, 51.

62 *Id*. at P 52.

The proposed Reliability Standards address the Commission's concerns by requiring Transmission Operators to plan to operate within all SOLs. Proposed Reliability TOP-001-3, Requirement R14 requires "each Transmission Operator to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment." Further, proposed TOP-001-3, Requirement R15 requires that each Transmission Operator inform its Reliability Coordinator of actions taken to resolve the SOL exceedance. Proposed IRO-008-2, Requirements R1, R2, R5, and R6 now include coverage of SOLs, which resolves the Commission's concern that the previously-proposed Reliability Standards limited "non-IROL SOLs" to only those internally identified by the Transmission Operator.

The Commission also proposed that the Transmission Operator should be required "to have an operational plan to operate within all Bulk-Power System IROLs and SOLs for all cases when facility ratings or stability limits are exceeded during anticipated normal and contingency event conditions."[63] The Commission noted that this operational plan "is needed to ensure that a Transmission Operator operates in, or can return its system to, a reliable operating state" and that a Transmission Operator should have plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.[64]

To address the Commission's concerns,[65] proposed Reliability Standard TOP-002-4 requires, among other things, that Transmission Operators have: (1) an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs; and (2) an Operating Plans for next-day operations to address potential SOL exceedances identified as a result of its Operational Planning

63 TOP/IRO NOPR at P 54.

64 *Id*. at P 54.

65 *Id*.

Analysis. Further, as noted above, proposed Reliability TOP-001-3, Requirement R14 requires Transmission Operators to initiate their Operating Plans to mitigate any SOL exceedances identified as part of its Real-time monitoring or Real-time Assessment."

The Commission also raised the concern that the Pending TOP/IRO Standards do not consider the possibility that additional SOLs could develop or occur in the same-day or Real-time operational time horizon, and therefore would pose an operational risk to the interconnected transmission network.[66] The Commission's concern is addressed in proposed Reliability Standard TOP-001-3, where operational responsibilities and actions pertaining to IROLs and SOLs are established for the real-time operational time horizon.

2. TOP Reliability Standards – Issues Requiring Clarification[67]

a. System Models, Monitoring and Tools

The Commission raised a concern about NERC's proposed retirement (on redundancy grounds) of TOP Reliability Standards associated with system computer models, monitoring equipment, metering, and analysis tools. The Commission stated that

> [m]onitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. . . . [C]ertification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.[68]

66 TOP/IRO NOPR at P 55.

67 In addition to the Issues Requiring Clarification discussed below, the Commission requested clarification on issues related to Reliability Standard PRC-001. As discussed above, issues related to PRC-001 are being addressed in a separate project.

68 TOP/IRO NOPR at P 60.

The Commission stated that the retirement of certain requirements in the currently effective IRO and TOP Reliability Standards addressing monitoring and analysis capabilities should not occur before the completion of NERC Project 2009-02.[69]

Proposed Reliability Standard TOP-001-3, Requirements R10 and R11 address this concern by adapting currently effective Reliability Standard IRO-003-2, Requirement R1 to Transmission Operators and Balancing Authorities. Specifically, TOP-001-3, Requirement R10 obligates each Transmission Operator to determine SOL exceedances within its Transmission Operator Area by monitoring facilities and the status of Special Protection Systems, and obtaining and using status, voltages and flow data for facilities and the status of Special Protection Systems outside of its Transmission Operator Area. Similarly, Requirement R11 directs each Balancing Authority to monitor its Balancing Authority Area, including the status of Special Protection Systems that affect generation or load, to maintain generation-load-interchange balance within its Balancing Authority Area and support interconnection frequency. Further, proposed Reliability Standard TOP-001-3, Requirement R13 also adapt currently effective Reliability Standard IRO-008-1, Requirement R2 to the Transmission Operator, requiring each Transmission Operator to perform a Real-time Assessment at least once every 30 minutes.

The proposed changes to Reliability Standard TOP-001-3, Requirements R10, R11 and R13 address the Commission's concerns about the retirement of the currently effective IRO and TOP requirements creating gaps on monitoring and analysis capabilities before the completion of Project 2009-02. Therefore, NERC does not propose a schedule as directed by the Commission to complete and implement Project 2009-02 prior to retiring these requirements.[70]

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69 TOP/IRO NOPR at P 61.

70 *Id*.

b. Compliance with Reliability Directives

The Commission expressed concern with NERC's proposed definition of "Reliability Directive" that could be interpreted as limiting the obligation to comply with Transmission Operator directives in emergencies only.[71] As discussed above, the proposed Reliability Standards used the proposed term "Operating Instruction" to provide additional clarity and specification to the circumstances under which entities must comply with a Transmission Operator's commands.

c. Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

The Commission expressed concerns that the Pending TOP/IRO Standards were unclear on the need for including external networks or sub-100 kV facilities in the Operational Planning Analysis conducted by Transmission Operators.[72] The proposed TOP Reliability Standards address this concern as follows. Proposed Reliability Standard TOP-003-3 requires each applicable entity to develop a data specification that would cover its data needs for monitoring and analysis purposes, including non-Bulk Electric System data and external network data deemed necessary by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (see Requirement R1, Part 1.1). Further proposed TOP-003-3, Requirement R5 requires Transmission Operators to supply data to Transmission Operator, thus making it clear that a Transmission Operator may request and receive data from outside of its immediate area. Similar requirements are proposed in IRO-010-2, Requirement R1, Part 1.1 for Reliability Coordinators.

[71] TOP/IRO NOPR at P 64.

[72] *Id*. at P 68.

The Commission also noted that Order No. 693 contained a directive to modify the TOP Reliability Standards for planned outage coordination to consider sub-100 kV facilities that the registered entity viewed as having a direct impact on Bulk-Power System reliability.[73] The Southwest Blackout Report recommended similar treatment of sub-100 kV facilities and external networks to ensure that Transmission Operators' next-day studies include all external networks and facilities that could affect the reliability of the Bulk-Power System.[74] Proposed Reliability Standard IRO-017-1 addresses outage coordination among the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. Together with the data specification requirements in proposed Reliability Standards TOP-003-3 and IRO-010-2, proposed Reliability Standard IRO-017-1 would help ensure that the outage coordination process established by Reliability Coordinator will consider sub-100 kV facilities that the relevant entities view as having a direct impact on Bulk-Power System reliability.

d. Operating to Respect the Most Severe Single Contingency in Real-Time Operations and Unknown Operating States

In the NOPR, the Commission expressed concern with the proposed retirements of TOP-004-2, Requirements R2 and R4, which include "three key rules, the requirements to be ready for the single largest contingency, to move quickly from an 'unknown operating state' to within proven limits, and to determine the cause of SOL violations in all time-frames, including real-time."[75] The proposed Reliability Standards maintain the reliability objective of operating to the most severe single contingency by requiring monitoring, notification, and actions to operate within

73 *See* TOP/IRO NOPR at P 68 (citing Order No. 693 at P 1624).

74 *See Id*. at P 68 (citing 2011 Southwest Outage Report, recommendation Nos. 2 and 3).

75 *Id*. at P 73. The Commission stated that "these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards."

SOLs and IROLs as discussed in preceding sections. Further, the FAC Reliability Standards currently require that SOLs provide a certain level of Bulk Electric System performance for the pre- and post-Contingency state. Additionally, the proposed definitions of "Real-time Assessment" and "Operational Planning Analysis" are strengthened to include Contingency conditions in the evaluations as follows:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

The proposed Reliability Standards require Transmission Operators to plan to operate within SOLs and to initiate Operating Plans to mitigate SOL exceedances. The Commission noted that a reliability objective should be to move quickly from an 'unknown operating state' to within proven limits.[76] The standard drafting team considers that, operationally, there always will be limits in service, and an operator should be obligated to adhere to the set of limits in service at the time a situation arises. The Commission's concern about an "unknown operating state" is addressed in proposed Reliability Standard TOP-001-3 and the SOL White Paper, attached as Exhibit E hereto, which explains how an SOL exceedance is determined and what entities do upon experiencing such an exceedance. Proposed Reliability Standard TOP-001-3, Requirement R13 specifies that Transmission Operators must perform a Real-time Assessment at least once every 30 minutes, which by definition is an evaluation of system conditions to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The Real-time Assessment

[76] TOP/IRO NOPR at P. 73

provides the Transmission Operator with the necessary knowledge of the system operating state to initiate an Operating Plan, as specified in Requirement R14, when necessary to mitigate an exceedance of SOLs, as described in the SOL White Paper. The SOL White Paper provides technical guidance for including timelines in the required Operating Plans to return the system to within prescribed ratings and limits.

Further, proposed Reliability Standard TOP-001-3, Requirements R12 and R13 address this concern by prohibiting a Transmission Operator from operating outside any IROL for a continuous duration exceeding its associated IROL T_v (Requirement R12), and requiring that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes (Requirement R13).

The Commission noted that importance of determining 'the cause of SOL violations in all time-frames, including real-time." Proposed Reliability Standard TOP-001-3, Requirement R10 addresses this point by ensuring appropriate action is taken to mitigate an exceedance, but does not specifically require that the cause of the violation must be determined in real-time. Instead, real-time efforts should be focused on resolving the exceedance with causes investigated, analyzed, and determined later and off-line. Pursuant to the revised definition of Real-time Assessment and proposed TOP-001-3, Requirement R13, which requires that a Transmission Operator perform a Real-time Assessment at least every 30 minutes, NERC believes that the Real-time Assessment conducted by Transmission Operators is sufficient for identifying "cause" for operators in Real-time.

Questions posed by the Commission with regard to the impact and usefulness of the proposed Real-time Assessment on smaller entities, who often maintain similar reliability based on operator experience,[77] are also addressed by the flexibility that provided in proposed Reliability Standard TOP-001-3, Requirement R13. Requirement R13 requires that a Real-time Assessment be performed every 30 minutes or less, but it does not mandate how it should be done. This requirement would allow smaller entities the flexibility to devise their own methods to comply with the requirement, including contracting with others to provide these services on their behalf.

e. Notification of Emergencies

In the NOPR, the Commission identified potential inconsistencies and ambiguities resulting from terminology used in the Pending TOP standards.[78] Proposed Reliability Standard TOP-001-3 uses the defined term "Emergency" in places where the Commission identified ambiguity, and applies the term to all operating time horizons. Further, the term Adverse Reliability Impact was eliminated from the proposed standard.

f. Primary Decision-Making Authority for Mitigation of IROLs/SOLs

The Commission sought clarification and technical explanation of whether Transmission Operators or Reliability Coordinators have primary responsibility for IROLs.[79] NERC hereby clarifies that the Reliability Coordinator has primary responsibility for IROLs, and the Transmission Operator has primary responsibility for SOLs, although the Reliability Coordinator must provide oversight on SOLs, as well as assistance in mitigating SOLs, as necessary. This split in responsibilities is important for the preservation of reliability within the Bulk Electric System

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77 TOP/IRO NOPR at P 74.

78 *Id*. at P 80-83.

79 *Id*. at P 87.

and consistent with the NERC functional model. The proposed Reliability Standards were designed to be consistent with these roles.

3. IRO Reliability Standards – Issues to be Addressed

a. Planned Outage Coordination

The Commission identified coordination of outages as "a critical reliability function that should be performed by the Reliability Coordinator" that is not adequately addressed in the Pending TOP/IRO Standards.[80] Proposed Reliability Standard IRO-017-1 addresses the Commission's NOPR concerns. Under the proposed standard, each Reliability Coordinator is required to develop, implement and maintain an outage coordination process for generation and transmission outages in its Reliability Coordinator Area. Each Transmission Operator and Balancing Authority, in turn, would be required to perform the functions specified in its Reliability Coordinator's process. Further, each Planning Coordinator and Transmission Planner will provide its Planning Assessment to relevant Reliability Coordinators and work together to solve any issues or conflicts with planned outages among the applicable entities. Additionally, proposed Reliability Standard IRO-014-3, Requirement R1, Part 1.4 requires Reliability Coordinators to include the exchange of planned and unplanned outage information to support Operational Planning Analyses and Real-time Assessments in the Operating Procedures, Processes, and Plans for activities that require coordination with adjacent Reliability Coordinators.

[80] TOP/IRO NOPR at P 90.

4. <u>IRO Reliability Standards – Issues Requiring Clarification</u>

a. Use of a Secure Data Network

The Commission sought assurance that the Pending TOP/IRO Standards provided for data exchange and notifications among Reliability Coordinators, Transmission Operators and Balancing Authorities "using a secure mode in a secure environment."[81] Proposed Reliability Standard TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3 specify that security is to be part of a data specification, and to be mutually agreed upon by the applicable registered entities. This proposed change makes clear that the data exchange and notifications among Reliability Coordinators, Transmission Operators, and Balancing Authorities "will be conducted using a secure mode in a secure environment."

b. Reliability Coordinator Monitoring of SOLs and IROLs

The Commission expressed concerns with proposed changes to the obligation of Reliability Coordinators to monitor SOLs in the currently effective IRO Reliability Standards.[82] The proposed Reliability Standards maintain the obligations for Reliability Coordinators to monitor SOLs. Specifically, proposed Reliability Standard IRO-002-4, Requirement R3 requires each Reliability Coordinator to monitor facilities, Special Protection Systems, and necessary non-Bulk Electric System facilities in order to identify SOL and IROL exceedances within its Reliability Coordinator Area.

E. Consideration of Outstanding Commission Directives

In developing the proposed Reliability Standards, the standard drafting team also addressed outstanding Commission directives relevant to the proposed Reliability Standards. Exhibit H

81 TOP/IRO NOPR at P 94.

82 *Id*. at P 96.

hereto provides a list of these outstanding directives and a description of the manner in which the standard drafting team addressed these directives. The following is a brief discussion of how the proposed Reliability Standards address the notable outstanding directives.

1. Outstanding Directives Related to the IRO Reliability Standards

- The Commission directed NERC to consider clarifying the requirement in IRO-001-1 that entities comply with a Reliability Coordinator's directive "unless such actions would violate safety, equipment or regulatory or statutory requirements."[83] As discussed above, that requirement is carried forward in proposed Reliability Standard IRO-001-4. The standard drafting team clarified during the development of the standard that the term "safety" should be read broadly to encompass the safety of both personnel and equipment and that no additional wording is needed.

- The Commission also directed NERC to consider stakeholder comments regarding the establishment of a chain of command so that, for example, if a Generator Operator receives conflicting instructions from a Balancing Authority and a Transmission Operator, it can determine which instruction governs.[84] The standard drafting team concluded that no additional medications to the proposed Reliability Standards are necessary. If Generator Operator receives conflicting Operating Instructions, the Generator Operator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.

- The Commission also directed NERC to consider stakeholder comments that Reliability Standard IRO-001-1 fails to address the operational limitations of qualifying facilities ("QFs") because QFs have contractual obligations to provide thermal energy to their industrial hosts and can only be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.[85] The standard drafting team concluded that no modifications to the proposed Reliability Standards were necessary because while a Reliability Coordinator can direct a QF to act in accordance with an Operating Instructions, the proposed Reliability Standards do not require a QF to comply if it would violate the QFs regulatory or statutory requirements.

- The Commission directed NERC to modify Reliability Standard IRO-002-1 to require a minimum set of tools that must be made available to the Reliability Coordinator.[86] This directive was beyond the scope of Project 2014-03 and is being addressed in a separate

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83 Order No. 693 at P 897.

84 *Id*. at P 897.

85 *Id*.

86 *Id*. at P 905.

standards development project (Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities).

- The Commission directed NERC to develop a modification to Reliability Standard IRO-003-1 to create criteria to define the term "critical facilities" in a Reliability Coordinator's area and its adjacent systems.[87] The proposed Reliability Standards no longer use the term "critical facilities." As discussed above, proposed Reliability Standard IRO-010-2 provides a mechanism for Reliability Coordinators to obtain data necessary to perform its reliability tasks, obviating the need for specific criteria for determining critical facilities.

- The Commission directed NERC to modify Reliability Standard IRO-004-1 to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency.[88] As described above, this issue is addressed in proposed Reliability Standards IRO-008-2 and TOP-002-4, as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. In short, SOLs must be controlled according to the Operating Plan, which is set up on time-based facility ratings. IROLs are controlled to the IROL Tv, which by definition is always less than 30 minutes. Commission-approved Reliability Standard IRO-009-1, also addresses this issue.

- The Commission directed NERC to include a requirement for the Reliability Coordinator to assess and approve actions that have impacts beyond the area views of Transmission Operators or Balancing Authorities, including how to determine whether an action needs to be assessed by the Reliability Coordinator.[89] Proposed Reliability Standard IRO-008-2, Requirements R2 and R5 address this directive by requiring Reliability Coordinators to (1) have coordinated Operating Plans for next-day operations, and (2) notify impacted Transmission Operators, Balancing Authorities and other Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

- The Commission directed NERC to provide clarification in proposed standards that Reliability Coordinators and Transmission Operators direct control actions of entities in their respective areas to respect System Operating Limits and Interconnection Reliability Operating Limits. [90] Proposed Reliability Standard IRO-001-4 Requirement R1 addresses this clarification in the case of the Reliability Coordinator as discussed above. (TOP-001-3 Requirement R1 addresses this clarification in the case of the Transmission Operator).

- In Order No. 693, the Commission also directed NERC to include the Reliability Coordinator as an applicable entity in Reliability Standard VAR-001-1 given its role as the highest level of authority overseeing the reliability of the Bulk-Power System.[91]

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[87] Order No. 693 at P 914.

[88] *Id*. at P 935.

[89] *Id*. at P 525.

[90] *Id*. at P 950.

[91] *Id*. at P 1855.

Although the directive related to the VAR standards, because the IRO standards address the Reliability Coordinator's oversight of Bulk-Power System facilities, the standard drafting team concluded that this directive is addressed in proposed Reliability Standard IRO-002-4, Requirement R3, which requires the Reliability Coordinator to monitor facilities, which would include voltage and reactive power resources.

- Similarly, the Commission directed NERC to develop a modification to INT-006-1 that makes it applicable to Reliability Coordinators and Transmission Operators, requiring them to review energy interchange transactions from the wide-area and local area reliability viewpoints, respectively, and, where their review indicates a potential detrimental reliability impact, communicate to the sink Balancing Authorities necessary transaction modifications before implementation.[92] Proposed Reliability Standard IRO-008-2 addresses this directive by requiring Reliability Coordinators to perform an Operational Planning Analysis, which requires Reliability Coordinators to consider Interchange, and develop a plan to address any problems. Similar requirements exist for the Transmission Operator in proposed Reliability Standard TOP-002-3.

- Directives pertaining to Reliability Standard PRC-001[93] are being addressed in a separate project to revise that standard.

2. Outstanding Directives Related to the TOP Reliability Standards

- The Commission directed to NERC to modify TOP-001-1 to define the term "emergency."[94] Proposed TOP-001-3 uses the defined term "Emergency" to improve clarity. The standard drafting team concluded that criteria for entering operating states belong in EOP standards, as noted by the Commission in Order 693.[95] Currently enforceable Reliability Standard EOP-002-3.1 - Capacity and Energy Emergencies and proposed Reliability Standard EOP-011-1 contain responsibilities.

- The Commission directed to NERC to consider stakeholder comments to require the Transmission Operator to notify the Reliability Coordinator or the Balancing Authority that it is removing facilities from service.[96] This directive is addressed in proposed Reliability Standard TOP-001-3, Requirement R8, which requires Transmission Operators to inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

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92 Order No. 693 at P 866.

93 *Id*. at P 1449.

94 *Id*. at P 1585.

95 *Id*. at P 560.

96 *Id*. at P 1588.

- The Commission directed revisions to TOP-002-2 and TOP-005-1 to deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.[97] As discussed above, proposed Reliability Standards IRO-010-2 and TOP-003-3 address security of data.

- The Commission directed revisions to TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.[98] As IROLs are the responsibility of the Reliability Coordinator, this issue is addressed in proposed Reliability Standard IRO-008-2 and Commission-approved Reliability Standard IRO-009-1, as discussed above.

- The Commission directed revisions to TOP-002-2 to require next-day analysis of minimum voltages at nuclear power plants auxiliary power busses.[99] This issue is addressed through proposed Reliability Standards IRO-010-2 and TOP-003-3, which provide Reliability Coordinators and Transmission Operators, respectively, a mechanism to acquire all of the data necessary for them to fulfill their reliability functions including non-Bulk Electric System data, as necessary. Next-day analysis is performed using Operational Planning Analysis.

- The Commission directed revisions to TOP-002-2 to also require simulation contingencies to match what will actually happen in the field.[100] The standard drafting team revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly to require Contingencies to match field conditions.

- The Commission directed NERC to revise TOP-003-0 to require the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of available transmission capability calculations.[101] Proposed Reliability Standard IRO-017-1 addresses this directive by requiring Reliability Coordinators to develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

- The Commission also directed NERC to revise TOP-003-0 to incorporate an appropriate lead-time for planned outages.[102] The standard drafting team determined that such a requirements is not necessary and could potentially conflict with existing rules in

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97 Order No. 693 at PP 1608, 1651.

98 *Id*. at P 1608.

99 *Id*.

100 *Id*.

101 *Id*. at P 1620.

102 *Id*. at P 1621.

organized markets. Nevertheless, pursuant to proposed Reliability Standard IRO-017-1, a Reliability Coordinator could include lead times in its process.

- The Commission directed NERC to consider whether to include breaker outages within the meaning of facilities that are subject to advance notice for planned outages.[103] Pursuant to IRO-017-1, a Reliability Coordinator could include breakers in its outage coordination process.

- The Commission also directed modifications to TOP-003-0 to require that any facility below the thresholds in Requirement R1 of that standard that, in the opinion of the Transmission Operator, Balancing Authority, or Reliability Coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to planned outage coordination.[104] Under proposed Reliability Standards IRO-010-2 and TOP-003-3, the Reliability Coordinator and Transmission Operator have a mechanism to obtain the data necessary to perform their reliability tasks, including identifying the appropriate facilities for outage coordination.

- The Commission directed modification to TOP-004-1 to require that the system be restored to respect proven limits as soon as possible taking no more than 30 minutes.[105] This directive is addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment, and the requirements in proposed Reliability Standard TOP-004-2 for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances.

- The Commission also directed revisions to TOP-004-1 to explicitly incorporate the interpretation of "multiple outages" as multiple element outages resulting from high-risk conditions.[106] The standard drafting team concluded that Commission-approved Reliability Standard EOP-001-2.1b, which covers emergency operations planning, already addresses this directive. In addition, Commission-approved Reliability Standard FAC-011-2 and FAC-014-2 includes specific requirements for dealing with multiple contingencies.

- The Commission also directed NERC to consider stakeholder comments that TOP-004-1, Requirement R2 should be revised to include frequency monitoring.[107] This directive is addressed by proposed Reliability Standards IRO-010-2 and TOP-003-3, which provide Reliability Coordinators and Transmission Operators a mechanism to obtain data on frequency, voltages, real and reactive power flows, and any other data that the entity needs.

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[103] Order No. 693 at P 1622.

[104] *Id*. at P 1624.

[105] *Id*. at P 1636.

[106] *Id*. at P 1638.

[107] *Id*. at P 1639.

- The Commission directed revisions to TOP-005-1 regarding the operational status of special protection systems and power system stabilizers.[108] The standard drafting team addressed this directive in proposed Reliability Standards IRO-010-2 and TOP-003-3 and in revising the definitions of Operational Planning Analysis and Real-time Assessments. Proposed Reliability Standards IRO-010-2 and TOP-003-3 specifically include a requirement to have provisions for notification of current Protection System and Special Protection System status or degradation.

- The Commission directed revisions to TOP-005-1 to add a requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.[109] This directive was beyond the scope of Project 2014-03 and will be addressed in a future standards development project (Project 2009-02 Real-time Monitoring and Analysis Capabilities).

- The Commission directed NERC to clarify the meaning of "appropriate technical information" concerning protective relays as used in TOP-006-1.[110] That term is not used in the proposed Reliability Standards. To address concerns about the status of protection systems, the standard drafting team incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards (i.e., proposed Reliability Standards IRO-010-2 and TOP-003-3).

- The Commission directed NERC to consider the Nuclear Energy Regulatory Commission's comments related to nuclear power plant voltage requirements.[111] Under proposed Reliability Standards TOP-002-3 and TOP-001-3, applicable entities must study minimum voltage limits, including those at nuclear plants.

In addition to the directives addressed by the standards drafting team, discussed above, NERC also notes that it resolved two directives from Order No. 748[112] that relate to the issues addressed by the proposed Reliability Standards. First, the Commission directed the NERC Reliability Coordinator Working Group to consider whether the need exists to refine the delineation of responsibilities between the Reliability Coordinator and Transmission Operator for

108 Order No. 693 at P 1648.

109 *Id*. at PP 1660, 1875.

110 *Id*. at P 1665.

111 *Id*. at P 1673.

112 *Mandatory Reliability Standards for Interconnection Reliability Operating Limits,* Order No. 748, 134 FERC ¶ 61,213 (2011).

analyzing certain "grid-impactive" SOLs that are of interest to the Reliability Coordinator.[113] Second, the Commission directed the NERC Reliability Coordinator Working Group to consider whether there is a need for reliability coordinators to have action plans developed and implemented with respect to certain "grid-impactive" SOLs that are of interest to the Reliability Coordinator.[114]

The working group, which included participation from the NERC Operating Committee and stakeholders, concluded that there was no need to create another category between IROL and SOL called "grid-impactive" SOLs. The working group determined that such a category could not be clearly defined and consequently did not support changes to the currently effective IRO standards. In addition to the working group action, the directives are addressed by proposed IRO-008-2 Requirements R1 and R2, which require the Reliability Coordinator to (1) analyze both SOLs and IROLs, as discussed above, and (2) must have a coordinated operating plan to address potential SOL and IROL exceedances which considers the operating plans provided by the Transmission Operators.

F. Enforceability of Proposed Reliability Standards

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[115]

The proposed Reliability Standards also include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and

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113 Order No. 748 at P 44.

114 *Id*. at P 55.

115 Order No. 672 at P 327.

Commission guidelines related to their assignment. Exhibit J provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Reliability Standards and associated elements included in Exhibit A;
- the proposed revised definitions to be incorporated into the NERC Glossary, included in Exhibit A; and
- the proposed Implementation Plan, including the noted retirements, included in Exhibit B.

Respectfully submitted,

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Date: March 18, 2015

Exhibit A

Proposed Reliability Standards and Definitions

Reliability Standard IRO-001-4

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose:** To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Generator Operator
   - **4.5.** Distribution Provider
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See the Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with the Reliability Coordinator's Operating Instructions, and compliance with the Operating Instructions could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1 .

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes "Distribution Provider" to "Transmission Service provider"	Errata
1	April 4, 2007	Approved by FERC – Effective Date	New
1.1	October 29, 2008	Removed "proposed" from effective date BOT adopted errata changes: updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approval	Revised
1	May 19, 2011	Replaced Levels of Noncompliance with FERC-approved VSLs	VSL Order
2	July 25, 2011	Revisions under Project 2006-06 to remove Requirement R7 to avoid duplication with IRO-014-2	Revised
2	August 4, 2011	Adopted by Board of Trustees	
3	July 6, 2012	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Revised the standard and retired six requirements (R1, R2, R4, R5, R6, and R9).	Revised

		Requirement R3 becomes the new R1 and R8 becomes the new R2 and R3.	
3	August 16, 2012	Adopted by Board of Trustees	Revised
4	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability:
Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5.

Rationale for Change from Reliability Directive to Operating Instruction:
The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

Rationale for Requirements R2 and R3:
The Transmission Service Provider has been removed from Requirements R2 and R3 as the Transmission Service Provider is not listed in the Functional Model as a recipient of corrective actions issued by the Reliability Coordinator. This allows for the retirement of IRO-004-2.

Reliability Standard IRO-002-4

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-4
3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Reliability Coordinator
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See the Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R2. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any

Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M4. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.

The Reliability Coordinator shall keep data or evidence for Requirement R4 and Measure M4 for the current calendar year and one previous calendar year.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R3	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Operating Limit exceedances within its Reliability Coordinator Area.
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.

4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Requirements:
The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

Rationale for R2:
Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

Rationale for R4:
Requirement R4 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

Reliability Standard IRO-008-2

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-2
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**
   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**
   See Implementation Plan.
6. **Background**
   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its

Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).
R4	Same-day Operations, Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's	For any sample 24-hour period within the 30-day retention period, the Reliability	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) or Interconnection Reliability	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in	(IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit	

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Requirement R5 was prevented or mitigated.	mitigated.	(IROL) exceedance identified in Requirement R5 was prevented or mitigated.	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

Rationale for R2 and R3:
Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

Rationale for R5 and R6:
In Requirements R5 and R6 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

Reliability Standard IRO-010-2

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability**
   - **4.1.** Reliability Coordinator.
   - **4.2.** Balancing Authority.
   - **4.3.** Generator Owner.
   - **4.4.** Generator Operator.
   - **4.5.** Load-Serving Entity.
   - **4.6.** Transmission Operator.
   - **4.7.** Transmission Owner.
   - **4.8.** Distribution Provider.
5. **Proposed Effective Date:**

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

- **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
- **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
- **1.3.** A periodicity for providing data.
- **1.4.** The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
				Assessments.	monitoring, and Real-time Assessments.	Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for Applicability Changes:

Changes were made to applicability based on IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.

The Interchange Authority was removed because activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.

The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard.

Rationale:

Proposed Requirement R1, Part 1.1:
Is in response to issues raised in NOPR paragraph 67 on the need for obtaining non-BES and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2:
Is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R3, Part 3.3:

Is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

Reliability Standard IRO-014-3

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators

2. **Number:** IRO-014-3

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date**

   See Implementation Plan.

6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. Criteria and processes for notifications.

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. Provisions for periodic communications to support reliable operations.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that its Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.

R4. Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

R5. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall have evidence that it developed an action plan during those instances where impacted Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation.

R6. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each impacted Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who identifies the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

R7. Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M7. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 and R2 and Measures M1 and M2.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement R5 and Measure M5.
- Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirement R6 and Measure M6.
- Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R3, R4, and R7 and Measures M3, M4, and M7.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability. OR, The Reliability Coordinator failed to implement its Operating Procedures, Operating processes, or Operating Plans when activities required notification, or coordination of actions with impacted adjacent Reliability Coordinators to support

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address one of the parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address two of the parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address all three of the parts specified in Requirement R2.
For the Requirement R3 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identifies the Emergency in its Reliability Coordinator Area failed to develop an action plan to resolve the Emergency during an instance where impacted Reliability Coordinators disagreed on the existence of Emergency.
R6	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identifies the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Emergency during an instance where Reliability Coordinators disagreed on the existence of the Emergency.
R7	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator had implemented its emergency procedures, unless such actions could not physically be implemented or would have violated safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" when used as adjective. 3. Changed standard header to be consistent with standard "Title." 4. Initial capped heading "Definitions of Terms Used in Standard." 5. Added "periods" to items where appropriate. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, self-certification. 8. Changed apostrophes to "smart" symbols. 9. Added comma in all word strings "Procedures, Processes, or Plans," etc. 10. Added hyphens to "Reliability Coordinator-to-Reliability Coordinator" where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	January 20, 2006
1	February 7, 2006	Adopted by Board of Trustees	Revised
1	March 16, 2007	Approved by FERC	
2	August 4, 2011	Revised per Project 2006-6; Revised existing requirements for clarity, retired R3 and R4 and incorporated requirements from IRO-015-1 and IRO-016-1 into this standard. Adopted by Board of Trustees	Revised

3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Terminology:
Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

Rationale for Requirement R7:
Language added for consistency with proposed TOP-001-3, Requirement R7.

Reliability Standard IRO-017-1

A. Introduction

1. **Title: Outage Coordination**

2. **Number: IRO-017-1**

3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.

4. **Applicability:**

    4.1. Reliability Coordinator

    4.2. Transmission Operator

    4.3. Balancing Authority

    4.4. Planning Coordinator

    4.5. Transmission Planner

5. **Effective Date:**

    See Implementation Plan.

6. **Background:**

    See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in its Reliability Coordinator's outage coordination process. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it jointly developed solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing all four of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator's outage coordination process.
R3	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its Planning Assessment to impacted Reliability Coordinators.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

Rationale for Time Horizon:
The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Rationale for R3:

Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

Rationale for R4:
The SDT has re-written Requirement R4 to show that the process starts with the Planning Assessments created by the Planning Coordinator and Transmission Planner and then those Planning Assessments are reviewed and reconciled as needed with the Reliability Coordinator. This is in response to comments in paragraph 90 of the FERC NOPR about directly involving the Reliability Coordinator in the planning process for periods beyond the present one year outreach as well as recommendations in the IERP. The re-write should not be construed as relieving the Reliability Coordinator of responsibilities in this area but simply as a reflection of how the process actually starts.

In the future, the SDT believes that such coordination should take place in the TPL standards and to support that position, the SDT has created an item in a draft SAR for TPL-001-4 that would revise Requirement R8 to make the Reliability Coordinator an explicit party in the review process described there.

In addition, the SDT will submit a request to the Functional Model Working Team to adjust the roles and responsibilities of the Reliability Coordinator to this new paradigm.

Reliability Standard TOP-001-3

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-3**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and R15 through R20 and Measure M1 through M11, and M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			communication channels between the affected entities.	associated communication channels between the affected entities.	channels between the affected entities.	unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.
R11	Real-Time Operations	High	N/A	N/A	The Balancing Authority did not monitor the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					balance within its Balancing Authority Area and support Interconnection frequency.	
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: http://www.nerc.com/pa/stand/Pages/TOP0013RI.aspx.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	February 12, 2015	Adopted by Board of Trustees	Revisions under Project 2014-03

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R3:

The phrase 'cannot be physically implemented' means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

Rationale for Requirement R10:

New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

Rationale for Requirement R13:

The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

Rationale for Requirement R14:

The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is to have a plan and philosophy that can be followed by an operator.

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity are deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

Rationale for Requirements R19 and R20:

Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

Reliability Standard TOP-002-4

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or e-mail records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not notify one impacted entity or 5% or less	The Balancing Authority did not notify two entities or more than 5% and	The Balancing Authority did not notify three impacted entities or	The Balancing Authority did not notify four or more entities or more than

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as identified in Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Definitions:

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:

Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:

The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:

Changes in response to IERP recommendation

Rationale for R4 and R5:

These Requirements were added to address IERP recommendations

Rationale for R6 and R7:

Added in response to SW Outage Report recommendation 1

Reliability Standard TOP-003-3

A. Introduction

1. **Title: Operational Reliability Data**

2. **Number: TOP-003-3**

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Load-Serving Entity

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the

Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Definitions:

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:

Changes to proposed Requirement R1, Part 1.1 are in response to issues raised in NOPR paragraph 67 on the need for obtaining non-BES and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data. The language has been moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability Coordinator.

Rationale for R5:

Proposed Requirement R5, Part 5.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

TOP/IRO Reliability Standards Definitions

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Definitions

Project 2014-03 Revisions to TOP/IRO Reliability Standards

As part of the work in Project 2014-03 Revisions to TOP/IRO Reliability Standards, the SDT is proposing changes to two existing definitions: Operational Planning Analysis and Real-time Assessment.

The currently-effective definition of Operational Planning Analysis is: "*An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).*"

The proposed version of the definition of Operational Planning Analysis is: "*An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)*"

The currently-effective definition of Real-time Assessment is: "*An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.*"

The proposed version of the definition of Real-time Assessment is: "*An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*"

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, TOP-003-3, IRO-002-4, IRO-008-2, and IRO-010-2. These definitions are not used in any other standards, either currently-effective or in development in any other project.

Exhibit B

Implementation Plan for Proposed Reliability Standards and Definitions

Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**
   - TOP-001-1a Reliability Responsibilities and Authorities
   - TOP-002—2.1b Normal Operations Planning
   - TOP-003-1 Planned Outage Coordination
   - TOP-004-2 Transmission Operations
   - TOP-005-2a Operational Reliability Information
   - TOP-006-2 Monitoring System Conditions
   - TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
   - TOP-008-1 Response to Transmission Limit Violations
   - IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
   - IRO-002-2 Reliability Coordination — Facilities
   - IRO-003-2 Reliability Coordination – Wide Area View
   - IRO-004-2 Reliability Coordination – Operations Planning
   - IRO-005-3.1a Reliability Coordination — Current Day Operations
   - IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
   - IRO-010-1a Reliability Coordinator Data Specification and Collection
   - IRO-014-1 Coordination Among Reliability Coordinators
   - IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
   - IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
   - PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project. Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:
   - TOP-001-2 Transmission Operations
   - TOP-002-3 Operations Planning
   - TOP-003-2 Operational Reliability Data
   - IRO-001-3 Reliability Coordination - Responsibilities and Authorities
   - IRO-002-3 Reliability Coordination — Analysis Tools
   - IRO-005-4 Reliability Coordination — Current Day Operations
   - IRO-014-2 Coordination Among Reliability Coordinators
   - PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the currently enforceable standards and definitions would remain effective until those approvals have occurred, and the new or revised standards in Project 2014-03 shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective three months earlier, in order to provide recipients of data requests from their Reliability Coordinators, Transmission Operators, and/or Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. **If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:**

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards meet or exceed the criteria.

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The proposed Reliability Standards achieve the specific reliability goal of addressing the roles and responsibilities of Reliability Coordinators, Transmission Operators, and Balancing Authorities with respect to planning and operating the Bulk Electric System. The proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the Bulk Electric System is operated within limits while enhancing situational awareness and strengthening operations planning.

The proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. Among other things, the proposed Reliability Standards help to ensure that Reliability Coordinators and Transmission Operators work together, and with other functional entities, to operate the Bulk Electric System within System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"). SOLs and IROLs are vital concepts in

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

NERC's Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in Exhibit J. The assignment of the severity level for each VSL is consistent with the corresponding requirement. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.** [5]

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.**[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards clearly articulate the reliability objectives that applicable entities must meet.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standards contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standards help ensure that entities coordinate efforts to plan and operate the Bulk Electric System in a reliable manner under normal and abnormal conditions...

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[5] Order No. 672 at P 327.

[6] Order No. 672 at P 328.

[7] Order No. 672 at P 329-30.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

The proposed Reliability Standards have no undue negative impact on competition. The proposed Reliability Standards require the same performance by each applicable entity. The standards do not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.[10]**

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation periods will allow applicable entities adequate time to meaningfully implement the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as Exhibit B.

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[8] Order No. 672 at P 331.

[9] Order No. 672 at P 332.

[10] Order No. 672 at P 333.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit K includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

[13] Order No. 672 at P 323.

Exhibit D

Mapping Document

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | Updated December 2014

This mapping document showing the translation of Requirements in the following currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions[1]
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

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[1] TOP-006-2 is the currently enforceable version of this standard; TOP-006-3 was developed in response to a request for interpretation seeking clarification of Requirement R1 and does not substantively change the Requirements of TOP-006-2. In its NOPR proposing to remand the TOP and IRO standard, FERC proposed to approve TOP-006-3. The drafting team has mapped the Requirements in the new standards to TOP-006-3 because the Parts of Requirement R1 in TOP-006-3 more clearly delineate which entity has responsibility.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** The SDT proposes retiring Requirement R2 as the regional reliability plan is a high level overview "how" document that shows how a Reliability Coordinator will comply with other NERC Standards. As a result, this requirement is administrative and redundant to other measureable and enforceable requirements within the standards. Since the requirement is generally administrative, it does not materially impact the reliability of the BES. The Reliability Plan concept is a holdover from the transition period from the Operating Policies to the Version 0 standards and was used extensively in the readiness evaluation process by the Operating Committee. The template used for the Reliability Plan is actually an outline of Operating Policy 9. The material included in the plan was a description of how an entity satisfied the specific functional areas under Policy 9. With the transition of Policy 9 to the IRO and other standards, the items addressed in

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	the reliability plans are inherently addressed in the body of other more measurable Reliability Standards.
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or by issuing Operating Instructions. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3. **Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator may implement alternate remedial actions.	
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed COM-001-2 Requirement R1 for voice links and proposed IRO-002-4 Requirement R1 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed COM-001-2, Requirement R1:** **R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R1:** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Approved PER-004-2, Requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, Part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, Part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability	This requirement is replaced by proposed COM-001-2 Requirement R1 and proposed IRO-002-4 Requirement R2. **Proposed COM-001-2, Requirement R1:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	**R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R2:** **R2**. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirements R3 and R4:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to	This requirement is replaced by proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R4:** **R4**. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R3 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have	This requirement is replaced by proposed IRO-002, Requirement R2 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R2:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
procedures in place to mitigate the effects of analysis tool outages.	**R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunications, monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R3 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	This requirement is replaced by proposed IRO-001-4, Requirement R1 since Operating Instructions, regardless of what timeframe they are issued for, are issued in a Real-time environment. In addition, roles for entities identified in the Operating Plans built from Operational Planning Analyses are communicated in proposed IRO-008-2, Requirement R3. **Proposed IRO-001-4, Requirement R1:** R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed IRO-008-2, Requirement R3:** R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s).

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	Replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and	The first sentence is replaced by proposed IRO-002-4, Requirement R3. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R3**:

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by approved EOP-010-1, Requirements R1 through R3. **Approved EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R3, R5 and R6. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-34 Requirements R3 and R4. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-010-2, Requirements R1, Part 1.2, and R3.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	**Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-010-4, Requirement R1, Part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses; **2.1.4.** Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall	The requirement is replaced by proposed IRO-008-2, Requirements R3, R5, and R6. **Proposed IRO-008-2, Requirement R3:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	**R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R4. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R3 and R5. **Proposed IRO-008-2, Requirements R3 and R5:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: **R1.1.** List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. **R1.2.** Mutually agreeable format. **R1.3.** Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). **R1.4.** Process for data provision when automated Real-Time system operating data is unavailable.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **1.3** A periodicity for providing data. **1.4** The deadline by which the respondent is to provide the indicated data. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.	This requirement is replaced by proposed IRO-010-2, Requirement R2. **Proposed IRO-010-2, Requirement R2:** **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Criteria and processes for notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Provisions for periodic communications to support reliable operations.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1, Part 1.5:** **R1, Part 1.5:** Provisions for periodic communications to support reliable operations.
R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R3 through R6 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. **Proposed IRO-014-3, Requirement R4:** **R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R5:** **R5**. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R6:** **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014 as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism. The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent in proposed TOP-001-4, Requirement R1 which states that the Transmission Operator must act or issue Operating Instructions.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R1: **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-4, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-4, R2: **Proposed IRO-001-4, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-4, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance at the Transmission Operator level is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. Balancing Authorities provide assistance under approved EOP-001-2.1b, Requirement R1. **Approved EOP-001.2.1b, Requirement R1:** **R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities**.** **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting entity has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: **R7.1** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-010-2, Requirement R3: **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – reactive power: Replaced by approved VAR-001-4, Requirement R3 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-4, Requirements R1 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved VAR-001-4, Requirement R3: **R3**. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	The Transmission Operator and Balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2 and proposed IRO-008-2, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-4, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-006-4, Requirement R5, and proposed TOP-002-4, Requirement R4. **Approved INT-006-4, Requirement R5:** **R5**. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Authorities have been removed from the applicability of this requirement. SOLs and IROLs are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13. Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs. Second sentence – SOLs are set by the Transmission Operator in approved FAC-014-2, Requirement R2 according to the methodology distributed by the Reliability Coordinator in approved FAC-011-2, Requirement R4, Part 4.3. This should assure that SOLs are consistent for common facilities. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved FAC-014-2, Requirement R2:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: 4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	2.4 Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
14.2 Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5, Part 5.2:** **5.2** A mutually agreeable process for resolving data conflicts

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators and Balancing Authorities through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. The data specification concept in proposed TOP-003-3 requires entities to provide data as requested. If there are outages of the equipment needed for providing that data, the entity experiencing the outage must notify the entity it is sending data to so that proper arrangements can be made for replacing the data or coming up with a plan to live without it. It is expected that the data specifications would incorporate such concepts. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, Requirement R2 and proposed IRO-017-1, Requirement R1, Part 1.4. **Proposed IRO-017-1, Requirement R1, Part 1.4**: **1.4** Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators **Proposed IRO-008-2, Requirement R2:** **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14 and proposed TOP-002-4, Requirement R2.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. **Approved FAC-014-2, Requirement R2:** **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Operator may take such actions, as it deems necessary, to protect its area.	Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: **6.1** Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-4, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R10, R12 and R14. **R6.2** has been replaced by proposed TOP-001-3, Requirement R8. **R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, Part 3.3:** **3.3** A mutually agreeable security protocol **Proposed TOP-003-3, Requirement R5, Part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data,**"** unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R3, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.**1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, Part 1.2; proposed TOP-003-3, Requirement R1, Part 1.2; and proposed TOP-003-3, Requirement R2, Part 2.2.; and the proposed changes to the definitions of Operational Planning Analysis and Real-time Assessment.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-003-3, Requirement R2, Part 2.2: **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R3. **Proposed TOP-001-3, Requirement R10:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to:
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R3, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R3**: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R5 and R6. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4.** When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4**. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R6. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Exhibit E

White Paper on System Operating Limit Definition and Exceedance Clarification

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

4. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.
4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

<u>Facility Rating Exceedance</u>

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

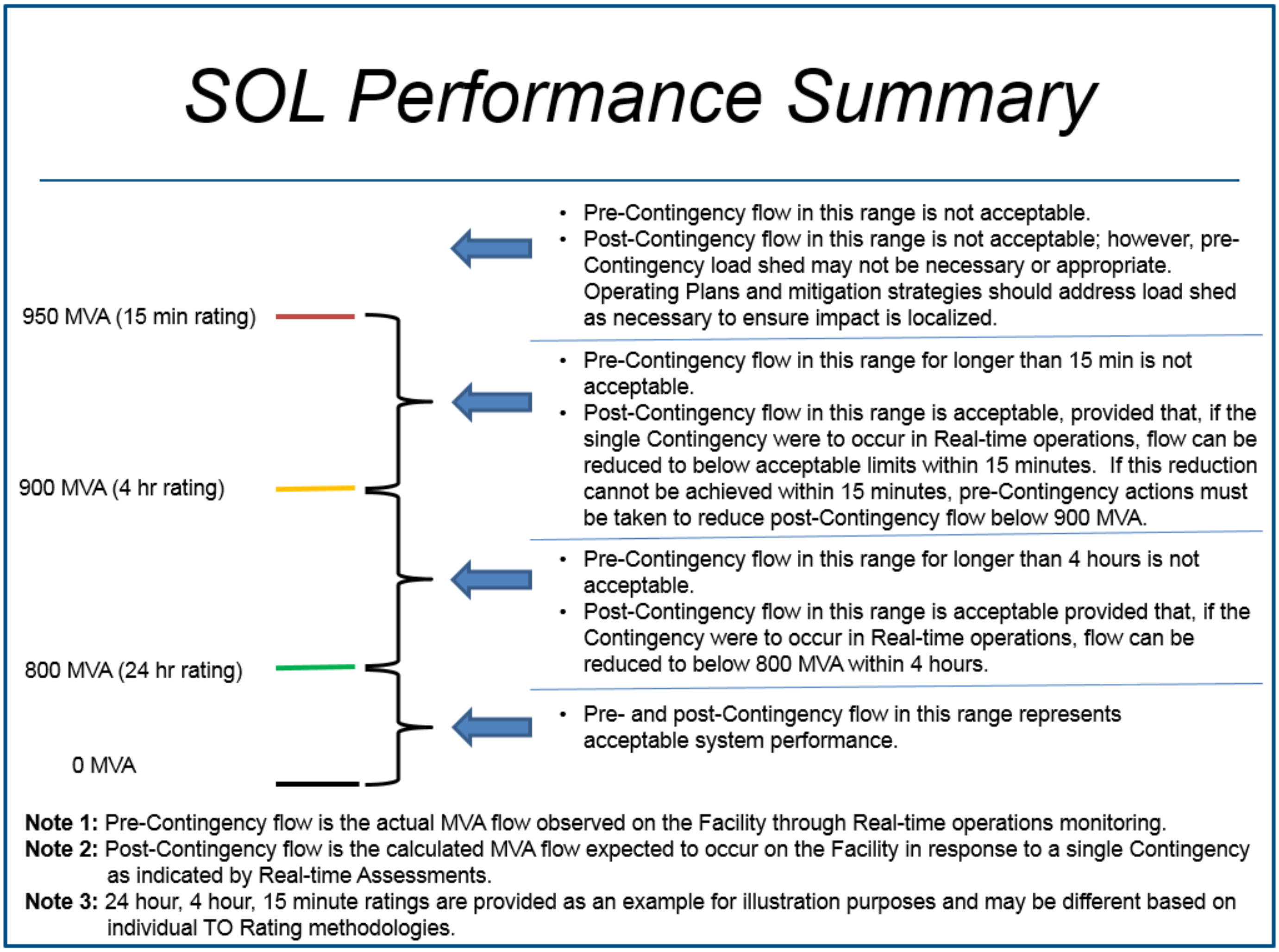

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner's or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

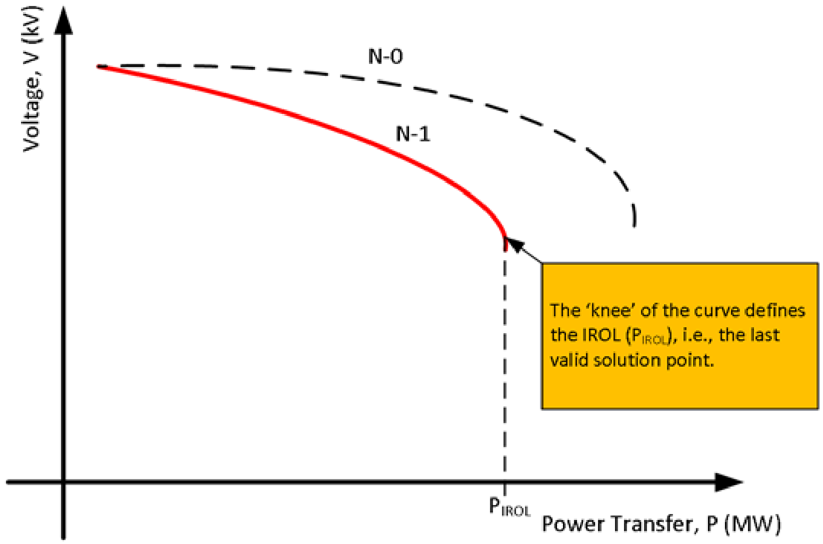

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in Operating Plan.**	**Use available effective actions and emergency procedures except Load shed consistent with timelines identified in Operating Plan.**
Emergency (15 min)	**All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in Operating Plan.**	**All of the above however, Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.**

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Exhibit F

Mapping Document of Proposed Reliability Standards to Southwest Outage Report Recommendations

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to have a coordinated Operating Plan(s) which will have required the Reliability Coordinator to have reviewed the plans submitted by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	 The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, Part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, Part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs’ and PCs’ studies. TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here. The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, Parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	elements operated at less than 100 kV on BPS reliability.	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Proposed TOP-003-3, Requirement R1, Part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-Contingency operating conditions.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R14**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures**.**	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, Part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		(Real-time Assessment may be provided through internal systems or through third-party services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	Model parameters are outside the scope of this project.
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for non-BES data and monitoring as deemed necessary by the reliability entities. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		proposed TOP-001-3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed IRO-002-4, Requirement R4**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved FAC-001-2, Requirement R3:** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: 3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) 3.4 Level of detail of system models used to determine SOLs.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
21	GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.	Outside the scope of this project.
24	TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay settings. No relay settings should be set below a facility’s emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.	Outside the scope of this project.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and	(1) Phase angle calculation tools are outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	(2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day	(2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability. Training is outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	contingency analyses that address the angular differences across opened system elements.	

Exhibit G

Summary of NOPR Issues

<u>TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)</u>

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

<u>Plan and Operate within all System Operating Limits</u>

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

<u>SDT Consideration:</u>

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R2, R5, and R6 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.
>
> Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.
>
> Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
>
> Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
>
> Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
>
> Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R3.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

SDT consideration:

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance.

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs.

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

<u>SDT consideration:</u>

See previous response.

<u>Compliance with Reliability Directives</u>

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

<u>SDT consideration:</u>

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

<u>SDT consideration:</u>

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

<u>SDT consideration:</u>

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
>
> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time

Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs.   This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.
>
> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

<u>SDT consideration:</u>

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.

> Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
>
> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An

Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

<u>SDT consideration:</u>

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying ‘cause’ for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

SDT consideration:

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
>
> Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.
>
> Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs

that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

<u>SDT consideration:</u>

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

<u>SDT consideration:</u>

<u>See response to paragraph 73 above.</u>

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers the situation where backup or redundant capabilities are required.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

<u>System Protection Coordination</u>

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

<u>SDT consideration:</u>

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

<u>Notification of Emergencies</u>

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

> Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-3, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

> Proposed IRO-014-3, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for

generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
1.1 Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
1.2 Specify outage submission timing requirements.
1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: A mutually agreeable security protocol.

Proposed IRO-010-2, Requirement R3, Part 3.3: A mutually agreeable security protocol.

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, non-BES data, and applicable relay data are included.

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Exhibit H

Consideration of Issues and Directives

Project 2014-03 - Revision of TOP / IRO Reliability Standards

Resolution of Issues and Directives

The following table contains a list of all FERC directives, industry issues, and Independent Expert Review Panel (IERP) recommendations associated with the standards being revised in Project 2014-03, with proposed resolutions.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	892. Consider commenters' suggestions as part of the standards development process. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.	The SDT has added measures for all requirements. The Regional Reliability Organization has been removed from the standards.
IRO-001-3	FERC Order 693	893. Consider commenters' suggestions as part of the standards development process. FirstEnergy	The SDT has considered the commenter's suggestions and believes that safety refers to any

Standard	Source	Language	Resolution
		suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.	type of safety including personal or equipment and that no additional wording is necessary. If a generator receives conflicting Operating Instructions, the generator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.
IRO-001-3	FERC Order 693	895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.	The SDT has considered the comments and believes that a Reliability Coordinator can direct a Qualifying Facility (registered as a GO or GOP) to act through the issuance of Operating Instructions. Therefore, no additional requirements are necessary.
IRO-001-3	FERC Order 693	896. Eliminate the references to the regional reliability organization as an applicable entity. Paragraph 896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 to substitute "Regional Entity" for "regional reliability organization" and reflect	The SDT has removed all references to the Regional Reliability Organization from the standards.

Standard	Source	Language	Resolution
		NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	
IRO-001-3	FERC Order 693	897. Consider adding measures and levels of non-compliance. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	The SDT has added measures and Violation Severity levels (VSLs) (which replaced levels of non-compliance) for each requirement.
IRO-001-3	FERC's December 20, 2007 and April 4, 2008 Orders	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance	The SDT has established requirements that apply to the Load-Serving Entity. **Proposed TOP-001-3, Requirement R3**: **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be

Standard	Source	Language	Resolution
		filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been	physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard	Source	Language	Resolution
		incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability First (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf)	

Standard	Source	Language	Resolution
		· NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.	
IRO-001-3	Fill in the Blank Team	Remove ", sub-region, or interregional coordinating group" from R1	Terms have been removed from the standard.
IRO-001-3	Version 0 Team	Inability to perform needs to be communicated	Clarity has been provided to address this issue throughout the various standards.
IRO-001	Version 0 Team	What is meant by 'interest of other entity'?	The SDT proposes to retire Requirement R9. All Reliability Coordinator Standard Requirements are developed so that the Reliability Coordinator shall act in the interest of reliability for the Reliability Coordinator Area and the Interconnection.
IRO-001-3	Fill in the Blank Team	Consider removing "Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market	The purpose statement has been revised accordingly.

Standard	Source	Language	Resolution
		participant over another." from the Purpose section of the standard.	Purpose: To establish the responsibility of Reliability Coordinators to act or direct other entities to act to prevent an Emergency.
IRO-001-3	NERC Audit Observation Team	All applicable registered functions shall comply with RC directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Inform the RC immediately of the inability to perform such directives. For audit purposes, what is acceptable evidence?	Measure M2 contains the provisions for suitable evidence. **Proposed IRO-001-4, Measure M2**: **M2**. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instruction, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator’s Operating Instruction. If no event has occurred, the Transmission Operator, Balancing Authority, Generator Operator, or

Standard	Source	Language	Resolution
			Distribution Provider may provide an attestation that an event has not occurred.
IRO-001-3	VRFs Team	R6 - Since the RC must be NERC certified, it stands to reason that anyone performing RC tasks should be certified. However, since the RC still retains the accountability for actions, and requirement 4 handles the agreements, this requirement is a medium risk.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
IRO-001-3	IERP	Requirement R1 content is incomplete. IERP recommended addressing 3 concepts as follows: RC has the authority to direct others to act. RC has the obligation to direct others to act to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.	The NERC Functional Model v5 spells out the authority of the Reliability Coordinator on page 30 under the description of the Reliability Coordinator functional entity. Proposed IRO-001-4, Requirement addresses the obligation of the Reliability Coordinator to direct others to act. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. The term 'Reliability Directive' has been replaced with the defined term 'Operating Instruction.' Proposed COM-002-4 determines the protocol for issuing Operating Instructions.

Standard	Source	Language	Resolution
		When directing others to act in accordance with this requirement, a RC must identify its directive as a "Reliability Directive". Consider consolidating with other authority-related standards and COM-003 in a single Authority standard as follows: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.	The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-001-3	IERP	IERP viewed Requirement R2 language as unclear and unable to be practically implemented. Questioned whether equipment requirements were a valid reason for not complying with RC direction. IERP proposed covering this requirement under a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.

Standard	Source	Language	Resolution
		safety, equipment, regulatory, or statutory requirements.	
IRO-001-3	IERP	IERP viewed content of Requirement R3 as incomplete by not requiring a reason for not complying with the RC's direction IERP recommended consolidating into a single Authority standard (see requirement above, which would replace both IRO-001 requirements R2 and R3)	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.
IRO-002-1	FERC Order 693	905 - Require a minimum set of tools that must be made available to the reliability coordinator. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.	This directive is beyond the scope of this project and will be resolved in a future project.
IRO-002	Version 0 Team	R5 – define synchronized information system	The term is not used in the revised standards.
IRO-002	Version 0 Team	R7 – define 'adequate' tools and 'wide-area'	The terms are not used in the revised standards
IRO-002-1	Version 0 Team	Words such as 'easily understood' and 'particular emphasis' need to be tightened	The terms are not used in the revised standards
IRO-002-3	IERP	IERP viewed Requirement R1 as incomplete. RC also needs to approve any other work being done on the tools, hardware/software/telecom systems within the RC that could affect the quality and the content of the data coming into the control center.	Proposed IRO-002-4, Requirement R2 addresses this issue. **Proposed IRO-002-4, Requirement R2**: **R2**. Each Reliability Coordinator shall provide its System Operators with the authority to approve

Standard	Source	Language	Resolution
		Also consider consolidating with Project 2009-02 Requirement R1 was proposed for consolidation under a new Authority standard: Authority R2 Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.	planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-002-3	IERP	IERP viewed Requirement R2 as incomplete. Procedures need to address not only tools outages, but also tools maintenance or other inhibitors to quality performance of analysis tools. Also consider consolidating with Project 2009-02	The SDT added 'maintenance' approval to proposed IRO-002-3, Requirement R3. This includes all work being done on monitoring and analysis capabilities and not just those that will cause an outage. **Proposed IRO-002-4, Requirement R2**: **R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Standard	Source	Language	Resolution
			The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards.
IRO-003	Order 693	914. … we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area …	The term is not used in the revised standards. The proposed data specification concept allows for the Reliability Coordinator to ask for any reliability related data that it needs in order to fulfill its reliability tasks thus obviating the need for a specific criteria for determining critical facilities. And specific requirements for monitoring have been added for the Reliability Coordinator. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
IRO-004-1	Order 693	934. In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each	Measures have been added to all requirements.

Standard	Source	Language	Resolution
		Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	
IRO-004-1	Order 693	935. …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency	The SDT has addressed this issue in proposed IRO-008-2 and TOP-002-4 as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. SOLs must be controlled according to the Operating Plan which is set up on time-based facility ratings (see SOL Exceedance White Paper for further details). IROLs are controlled to the IROL T_v which by definition is always less than 30 minutes. Approved IRO-009-1, Requirement R1 also addresses this item. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard	Source	Language	Resolution
			Proposed TOP-002-4, Requirement R1: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed IRO-009-1, Requirement R1**: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
IRO-005	FERC Order 693	520. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have	The SDT addresses the need for Reliability Coordinator assessment and approval on a requirement by requirement basis. For example, see proposed IRO-008-2, Requirements R3 and R6.

Standard	Source	Language	Resolution
		impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR. 525. Accordingly, we direct the ERO to include a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities, including how to determine whether an action needs to be assessed by the reliability coordinator. This Requirement is best developed under the Reliability Standards development process including the consideration whether this Requirement should be included in this communications Reliability Standard or an operating Reliability Standard.	**Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R5**: **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
IRO-005-1	FERC Order 693	946. "Conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROLS, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to NERC.	Completed and filed in Oct 2008
IRO-005-1	FERC Order 693	950- Provide further clarification that reliability coordinators and transmission operators direct control	The SDT has proposed IRO-001-4, Requirement R1 to address the Commission's suggestion for

Standard	Source	Language	Resolution
		actions, not LSEs as part of the standard development process. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.	clarification. Proposed TOP-001-4, Requirement R1 also addresses this issue. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed TOP-001-4, Requirement R1:** **R1.** Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
IRO-005-1	FERC Order 693	951-"Measures and levels of non-compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency, and causes of the violations and whether these occur during normal or contingency conditions. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO-005-1through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration,	The SDT has added measures and VSLs (which replaced levels of non-compliance) for each requirement.

Standard	Source	Language	Resolution
		frequency and causes of the violations and whether these occur during normal or contingency conditions.	
IRO-005-1	Fill in the Blank Team	R14 has regional reference	The term is not used in the revised standards.
IRO-005-1	Version 0 Team	R10, 11 & 12 – RA not empowered to do this	RA is no longer an applicable entity in the revised standards.
IRO-005-4	IERP	Requirement R1 is incomplete--needs to include Emergency. Requirement R1 reads: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. Also - there are gaps between the old std IRO-005-3 R2 to IRO-005-4: missing is: There is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard	The SDT replaced Adverse Reliability Impact with Emergency in all requirements. Emergency is a broader term. Proposed IRO-002-4, Requirement R3 addresses the issue of monitoring. **Proposed IRO-002-4, Requirement R3**:

Standard	Source	Language	Resolution
		and Disturbance Control Standard requirements. (Minus strikethrough) FROM IRO-005-3 R9: Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. The SDT believes all appropriate items, including Special Protection System evaluation and awareness is addressed through the revised definitions of Real-time Assessment and Operations Planning Analysis. The data specification has been revised to explicitly address Special Protection Systems. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1. Part 1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
		From IRO-005-3 R10: In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	The SDT has addressed the issue of resolving differences in limits in proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R18**: **R18.** Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.

Standard	Source	Language	Resolution
		Recommend consolidating with IRO-008 R3.	The SDT has consolidated requirements and standards as it believes appropriate.
IRO-005-4	IERP	The proposed standard creates a gap in outage coordination by proposing to retire IRO-005-3 R6. This could be resolved through an Authority standard as proposed by the IERP From IRO-005-3 R6: The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The SDT has proposed a new standard, IRO-017-1 Outage Coordination, to address this issue.
IRO-005-4	IERP	Requirement R2 should also include Emergency Requirement R2 reads: Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated. Note: there is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1	The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency.

Standard	Source	Language	Resolution
		Recommend moving to IRO-008 and create an R4	
IRO-014-2	IERP	Gap in Requirement R1 - Need to identify RC's authority to direct another RC to take action - suggestion: create another Requirement, i.e., R6 (in proposed authority standard). Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT does not agree with this recommendation. A Reliability Coordinator does not direct another Reliability Coordinator. Proposed IRO-014-3 describes how to coordinate between Reliability Coordinators.
IRO-014-2	IERP	R2 is administrative and should be deleted	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R3 implements plan from R1; it should be combined with R1	The SDT believes that combining the requirements would create a complex requirement with multiple objectives that would be difficult to measure for compliance.
IRO-014-2	IERP	Requirement R4 is administrative and should be deleted.	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R5 should require notification of “all IMPACTED RCs"; not "ALL"	The SDT has added ‘impacted’ to appropriate locations in the standards.
IRO-014-2	IERP	R6 should be consolidated with other standards that incorporate the concept of operating to the most conservative for reliability - IRO-009-1 R5	Approved IRO-009-1 only addresses IROLs. Proposed IRO-014-3 addresses all limits.

Standard	Source	Language	Resolution
		R6 reads: During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.	
IRO-014-2	IERP	Requirement R7 should be retired. The reliability objective is covered under R6, and also supported by IRO-009-1 R5	The SDT believes that the two requirements are sufficiently distinct to warrant separateness. Requirement R6 speaks to actual operations. Requirement R7 speaks to having an established plan. The SDT believes that reliability is best served by having a plan to follow.
IRO-014-2	IERP	Requirement R8 should be retired. The reliability objective is covered under R6.	The SDT does not agree with this recommendation. Requirement R8 is a separate requirement.
IRO-016	VRF's Team	R1.2.1 & R2 – ambiguous	Requirement R2 was approved for retirement by FERC effective January 2014. Requirement R1, part 1.2.1 was incorporated in the set of requirements in proposed IRO-014-3, and ambiguous language has been deleted.
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in

Standard	Source	Language	Resolution
			the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This concern is addressed in proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	The term is not used in the revised standards
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been revised to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is

Standard	Source	Language	Resolution
			listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-001-2	IERP	Requirement R1 phrase "unless it violates requirements" is too permissive or there may be a better way to phrase it Consider consolidating TOP-001-2 Requirements R1 and R2 and all other standards requirements related Authority to into a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under [Authority standard R1] unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT believes that this is well understood language. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
TOP-001-2	IERP	The language “emergency assistance” in Requirement R4 is unclear. When and how must assistance be rendered, and what type? BA’s should be included as functional entity. Consider moving R4 to EOP standards (this is an "emergency" operating requirement)	The SDT revised the language for clarity and included the Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7**. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures,

Standard	Source	Language	Resolution
			unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
TOP-001-2	IERP	Requirement R5 should also include notification of Emergencies (in addition to ARI), and should include Bas. R5 states: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.	The SDT added impacted Balancing Authorities. The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-2	IERP	R6 needs to include real time outages of telecom as well as planned outages.	The SDT added telecommunications to the requirement. **Proposed TOP-001-2, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between it and the affected entities. COM standards are not in scope for this project.

Standard	Source	Language	Resolution
		Requirement should be covered under COM-001	
TOP-001-2	IERP	Requirement R8 does not cover all information needed for reliability. It should cover 1) SOLs within a TOP's/RC's footprint, 2) SOLs that are within one TOP's/RC's footprint that could affect another entity and 3) an SOL that spans into 2 TOP's/RC's footprints The requirement should also obligate the TOP to also inform impacted TOPs (The entity that could be impacted must tell the TOP that could impact them that it needs the info)	The SDT has addressed issue 1 in proposed TOP-001-3, Requirement R15. SOLs that cross boundaries are taken care of at the Reliability Coordinator level. **Proposed TOP-001-3, Requirement R15:** **R15**. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.
TOP-002-3	Order 693	1597. Consider ISO-NE recommendation that the reference to "transmission service provider" in TOP-002-2 R12 be replaced by TOP and/or TO. Requirement R12 states: The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.	This requirement is now addressed by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **R6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or

Standard	Source	Language	Resolution
			A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3**: **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. Approved MOD-030-2, Requirement R2.4: Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
TOP-002-3	Order 693	1598. Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including non-BES data as necessary. Next-day analysis is performed using Operational Planning Analysis. Approved NUC-001-2.1 also applies here. **Proposed IRO-010-2, Requirement R1 and Part 1.1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-

Standard	Source	Language	Resolution
			time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed Definition: Operational Planning Analysis** - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs

Standard	Source	Language	Resolution
			including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
TOP-002-3	Order 693	1600. Address critical energy infrastructure confidentiality as part of the routine standard development process	The data specification standards now contain provisions for addressing security of data. **Proposed IRO-010-2, Requirement R3, Part 3.3**: **R3. Part 3.3** A mutually agreeable security protocol. **Proposed TOP-003-3, Requirement R5, Part 5.3:** **R5. Part 5.3** A mutually agreeable security protocol.
TOP-002-3	Order 693	1601. …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages	SOLs are the responsibility of the Transmission Operator and IROLs are the responsibility of the Reliability Coordinator. This issue is addressed in proposed changes to the IRO standards. Approved IRO-009-1, Requirement R1 also applies. **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R2: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3**: **R3**. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
TOP-002-3	Order 693	1606. Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm	The SDT agrees and has addressed the issue in proposed TOP-002-3, Requirement R4, part 4.4:

Standard	Source	Language	Resolution
		load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.
TOP-002-3	Order 693	1608. Require simulation contingencies to match what will actually happen in the field	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly. The definitions require Contingencies to match field conditions as they require evaluations against projected system conditions for Operational Planning Analysis and system conditions for Real-time Assessment. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The

Standard	Source	Language	Resolution
			assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
TOP-002-3	IERP	Requirement R1. TOP-008-1 R4 needs to be incorporated into TOP-002-3 requirement R1. Also - the definition of "Operational Planning Analysis" provides too much latitude in time. Recommend removing the parenthesis in the definition; the entity will make the determination and document (documentation is evidence) the applicability of what it uses for their next day study	The SDT revised the definition of Operating Planning Analysis and Requirement R1. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next

Standard	Source	Language	Resolution
			day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
TOP-003-0	FERC Order 693	1620. …direct the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these type of issues, specifically proposed IRO-017-1, Requirement R1. This new standard takes into account the recommendations from the Independent Expert Review Panel and SW Outage Report and brings all of the various outage coordination issues into one cohesive standard. **Proposed IRO-017-1, Requirement R1:** **R1**. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of Project 2007-03 in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional

Standard	Source	Language	Resolution
			standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. In response to concerns raised by the IERP and the SW Outage Report, the SDT has developed proposed IRO-017-1 Outage Coordination. This standard requires the development of a coordinated outage process between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. If so desired, a Reliability Coordinator could include lead times in its process. (See proposed IRO-017-1, Requirement R1, Part 1.2.) In addition, proposed IRO-010-2 and TOP-003-2 dealing with data specifications could also cover this issue. The data specification must include any and all data required by the Reliability Coordinator, Transmission Operator and Balancing Authority. Planned outage data and timings could be included in such a data specification.

Standard	Source	Language	Resolution
			Therefore, the SDT has not included a standard lead time in the revised requirements. **Proposed IRO-017-1, Requirement R1, Part 1.2:** **1.2** Specify outage submission timing requirements.
TOP-003-0	Order 693	1622. Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these types of issues. **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	Order 693	1624. Direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and Part 1.1**: **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time

Standard	Source	Language	Resolution
			monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
TOP-003-2	IERP	Requirements R1 and R2 do not address level of accuracy required; see if this is provided elsewhere (i.e. project 2009-02) Consolidate R1 and R2 at minimum; at max consolidate with RC (IRO-010-1a R1)	Level of accuracy is one of the issues identified in the Real-Time Tools Best Practices Task Force Report. NERC is currently instituting a review of all of the recommendations in various reports, including the Real-time Tools Best Practices Task Force report, to see what actions should be taken, if any are still required, to address recommendations in the reports. The SDT does not want to consolidate the two responsibilities. The industry has clearly indicated a desire for separate standards for the Reliability

Standard	Source	Language	Resolution
			Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Consolidate R3 and R4 at minimum; at max consolidate with RC (IRO-010-1a R2)	The SDT does not want to consolidate the two requirements or the two standards. The SDT feels Requirements R3 and R4 are for different tasks. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Requirement R5 should be consolidated with IRO-010-1a R3	The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	The SDT believes that this issue has been addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment, and the requirement for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances. The SDT has developed a white paper on the topic of SOL exceedance to explain the technical rationale behind this resolution. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known

Standard	Source	Language	Resolution
			Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R1**: **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances

Standard	Source	Language	Resolution
			identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14**: **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
TOP-004-1	Order 693	1637. …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Completed and filed in Oct 2008.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (… the Commission proposed to interpret “multiple outages” in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an	The SDT feels that approved EOP-001-2.1b dealing with emergency operations planning covers the intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, approved FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under … high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	Order 693	1639. Consider Santa Clara's comment in the SDT process. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows	The data specification standards require that entities obtain all of the data that they need to perform their reliability functions. This would include frequency, voltages, real and reactive power flows, and any other data that the entity needs. Proposed TOP-001-3, Requirements R10 and R11 also address this item. **Proposed IRO-010-2, Requirement R1**: **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-001-3, Requirement R10**:

Standard	Source	Language	Resolution
			R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11**. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	The SDT has clarified the issue. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL $T_{v.}$
TOP-005	Order 693	1648. ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status	The SDT has added specific parts to the data specification standards as well as revising the

Standard	Source	Language	Resolution
		of special protection systems and power system stabilizers in Attachment 1.	definitions of Operational Planning Analysis and Real-time Assessment to address this issue. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**:

Standard	Source	Language	Resolution
			1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-005	Order 693	1650. Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process. FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. ISO-NE recommends that the reference to “purchasing-selling entity” should be replaced with LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-3. Requirement R4 has been superseded by proposed TOP-003-3 which does include the indicated entities and has deleted PSE. **Proposed TOP-003-3, Requirement R5**: **R5.**Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
TOP-005	Order 693	1651. … deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.	The SDT believes that confidentiality is a market issue and not a reliability issue and as such it does not belong in the Reliability Standards. However, security of information is a reliability concern and the SDT has addressed that issue through the addition of requirements for establishing security protocols in data exchanges.

Standard	Source	Language	Resolution
			Proposed TOP-003-3, Requirement R5, Part 5.3: 5.3 A mutually agreeable security protocol. **Proposed IRO-010-2, Requirement R3, Part 3.3**: 3.3 A mutually agreeable security protocol.
TOP-005	Order 693	1660. Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system	This directive is beyond the scope of this project and will be resolved in a future project.
TOP-006	Order 693	1665. Clarify the meaning of appropriate technical information concerning protective relays	That term is no longer used in the standards. To address concerns about the status of protection systems, the SDT has incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-006	Order 693	1664/1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	All requirements now have measures.
TOP-006	Order 693	1673. Direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan.	Analysis is required in proposed TOP-002-3, Requirement R1 and in proposed TOP-001-3, Requirement R13. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1 and proposed

Standard	Source	Language	Resolution
		NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.	TOP-001-3, Requirement R13 as shown in the revised definition of Operational Planning Analysis and Real-time Assessment. Additionally, approved NUC-001-2.1, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-3. Approved NUC-001-2, Requirements R3 & R8 cover the information flowing back to the nuclear plant operator. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential

Standard	Source	Language	Resolution
			(post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved NUC-001-2.1, Requirement R3**: **R3**. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. **Approved NUC-001-2.1, Requirement R4.1**:

Standard	Source	Language	Resolution
			4.1 Incorporate the NPIRs into their operating analyses of the electric system. **Approved NUC-001-2.1, Requirement R8:** **R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.
VAR-001-1	Order 693 Transferred from Project 2013-04 Voltage and Reactive Control	1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in	The SDT has clarified the issue of having the Reliability Coordinator provide oversight. The proposed requirement uses the term 'Facilities' which is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." Therefore, the requirement covers voltage and reactive resources. **Proposed IRO-002-4, Requirement R3**: **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any

Standard	Source	Language	Resolution
		VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
INT-006-1	Order 693 Transferred from Project 2008-12 Coordinate Interchange Standards	866. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that makes it applicable to reliability coordinators and transmission operators. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	An equally efficient and effective method of addressing the directive was approved by the Board and filed with FERC by Project 2008-12 SDT by including the term 'Interchange' in the definition of Operational Planning Analysis. This change has been retained by Project 2014-03. Proposed IRO-008-2, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. Then, in proposed IRO-008-2, Requirement R2, the Reliability Coordinator must develop a plan for addressing the problem. Similar requirements exist for the Transmission Operator in proposed TOP-002-3. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including,

Standard	Source	Language	Resolution
			but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:**

Standard	Source	Language	Resolution
			R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R3:** **R3**. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

Exhibit I

Consideration of NERC Operating Committee Response to NERC Standards Committee RISC Triage of IERP Gaps

NERC Operating Committee Response to NERC Standards Committee / RISC Triage of IERP Gaps

April 2, 2014

The NERC Operating Committee reviewed three perceived gaps, Outage Coordination, Governor Frequency Response, and Situational Awareness, as identified by the Independent Experts in their June 2013 report. As an important step in this review, the OC's Executive Committee met via WebEx with the Independent Experts to more thoroughly discuss and understand the thinking which led to these elements being cited as possible gaps. During the WebEx, the OCEC and the Independent Experts also reviewed all of the proposed requirements in the Independent Experts draft Authority matrix. The results of the OC's discussions, and the Project 2014-03 SDT's consideration within the revised TOP and IRO standards for two of the three perceived gaps (Outage Coordination and Situational Awareness) are presented below. The third gap identified by the Independent Experts, Governor Frequency Response, is outside the scope of Project 2014-03.

Outage Coordination

Draft requirements 3, 7, 8 and 9 of the Independent Experts draft Authority Standard focus on Outage Coordination. One concern recognized the fact that the Reliability Coordinators have a wide area view and broader situational awareness, allowing for early identification and resolution of conflicts. Therefore the RCs should have the most influence on outage coordination. Further concerns identify standards that are currently in flux, particularly those remanded standards in which requirements are being removed.

> Operating Committee opinion
>
> The Operating Committee concurs that Outage Coordination is an important grid reliability function. Outage coordination should originate from the TOPs and GOPs; with conflicts resolved by their respective RC. It makes sense for this process to begin with a set of previously approved scheduled long term outages with a sufficient time margin for results to be incorporated into seasonal operating studies. Further, the RC should retain the authority for final approval up to the time the asset is removed from service, as well as recall authority (if technically feasible and appropriate to recall) as needed to prevent or mitigate emergencies.
>
> Longer term outage coordination is necessary for those assets that require long maintenance planning pursuant to the type of work required, such as turbine rebuilds, nuclear refueling, etc. This likely belongs in the scope of the Planning Coordinator (PC) for outages planned more than 12-months into the future. A Reliability Standard could be written that requires PCs to coordinate long term outages and which requires responsible entities (e.g., GOs, TOs) to request a time slot in which to perform whatever maintenance is required.

In either case, during the longer term planning horizon, or the Operations planning and real time operations time frame, each PC or RC should have an understanding of the impacts on neighboring PCs or RCs when those assets are planned to be out or are forced out, with notification/coordination requirements with these PCs or RCs.

SDT response:

To enhance reliability, the Project 2014-03 SDT has provided explicit requirement language to address the need for planned outage coordination at the Reliability Coordinator level. See proposed IRO-014-3, Requirement R1, part 1.4. The Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address overall outage coordination issues.

Proposed IRO-014-3, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Situational Awareness (EMS RTCA models)

In this gap the Independent Experts recommend the development of a standard that defines the requirements for EMS RTCA models or performance expectations of the models (Project 2009-02 – Real Time Monitoring and Analyses Capabilities).

Operating Committee opinion

The Operating Committee has a concern that this gap could be interpreted as recommending a "HOW" standard where specific tools would be required even for the smallest TOPs, as opposed to a "WHAT" standard that would allow for other ways to accomplish the objective. In conversations with the Independent Experts it became clear that proper situational awareness was the primary concern. The OC concurs that real time contingency analysis process (real time updated topology and telemetry) should be performed on each BES facility. This functionality could be performed by use of an RTCA application at the TO or RC level, or coverage by alternate means would be appropriate.

SDT response:

The Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13. In addition, the Project 2014-03 SDT has revised the definition of Real-time Assessment to allow for contracting needed services to accommodate concerns for smaller entities.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase

angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Remainder of the draft Authority Standard Requirements

Authority R1

Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.

Operating Committee opinion

The current IRO-001-1.1 and TOP-001-1a are expected to be retired and replaced by IRO-001-3. In either case, these standards contain the authority to act, but the requirement to act appears to be implicit. The OC agrees that the RC, TOP and BA should explicitly be required to act.

SDT response:

The Project 2014-03 SDT agrees and has adjusted the wording in the standards to address this issue.

Proposed IRO-001-4, Requirement R1: Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R1: Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R2: Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

Authority R2

Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.

Operating Committee opinion

The current IRO-002-2 provides for the RC to have control of its tools but does not include the TOP or BA. IRO-002-2 is expected to be retired and replaced by IRO-002-3, which clarifies that the system operators have the authority to approve outages of analysis tools (The OC suggests adding “under the direct control of their company”), but does not include TOPs or BAs. The OC concurs

with the clarification in IRO-002-3, and the OC further agrees that TOPs and BAs should be included.

SDT response:

The Project 2014-03 has added proposed TOP-001-3, Requirements R16 and R17 to provide Transmission Operators and Balancing Authorities with capabilities similar to those of the Reliability Coordinator.

> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

> Proposed TOP-001-3, Requirement R17: Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Authority R4

RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.

Operating Committee opinion

During the OCEC/Independent Expert webex, the Independent Experts explained that the objective of this requirement is to mandate the posting of a letter in the control rooms granting authority to the system operators to carry out their required tasks. While the Operating Committee believes this is a good practice, it does not believe that it rises to the level of a Standards Requirement.

SDT response:

The Project 2014-03 SDT agrees with the position of the Operating Committee Executive Committee. A letter of authority located in the Control Room is an example of good utility practice. A change to the requirements is not warranted.

Authority R5

Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

In relation to R1 above this understanding seems implicit. However, in the interest of clarity the OC would support this requirement.

SDT response:

The Project 2014-03 SDT agrees.

Proposed TOP-001-3, Requirement R3: Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed TOP-001-3, Requirement R5: Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed IRO-001-4, Requirement R2: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Authority R6

Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

IRO-014-5, IRO-015-1 and IRO-016-1 describe inter RC procedures, Plans, notifications and coordination. These standards are expected to be retired and replaced by IRO-014-2 incorporating the pertinent requirements from the retiring standards. However, none of these standards explicitly include a requirement for one RC to comply with a directive from another RC.

The OC recognizes that coordination between RCs is vitally important. It is also recognized that an RC is the entity with the best understanding and situational awareness of its unique footprint. Therefore it is not believed to be beneficial for operational reliability for one RC to direct the actions of another RC. Rather, it is more appropriate to have this type of coordination documented within the requisite Joint Operating Agreements in which the appropriate assistance would be documented and understood in advance of such actions.

SDT response:

The Project 2014-03 SDT believes that proposed IRO-014-2 Requirements R3 – R6 already require Reliability Coordinators to coordinate and implement action plans even if the RC cannot agree that a problem exists or what the exact action plan is

> Proposed IRO-014-2, Requirement R3: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.
>
> Proposed IRO-014-2, Requirement R4: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R5: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R6: Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Exhibit J

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities and the status of Special Protection Systems within the Transmission Operator's Area and to obtain data outside of the Transmission Operator's Area for Facilities and status of Special Protection Systems identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor the status of Special Protection Systems that impact generation or Load could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed TOP-002-4. All of the requirements were assigned a Medium VRF.

VRF for Proposed TOP-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk

power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in proposed TOP-003-3. Four of the five requirements were assigned a "Low" VRF: Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for Proposed TOP-003-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator and proposed TOP-003-3, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the

bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: approved IRO-010-1 for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R5, has only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-001-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-001-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking actions to preserve reliability.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to act, or direct others to act, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with Operating Instructions could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of the inability to follow an Operating Instruction could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-002-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to give operators the authority to approve planned outages and maintenance of telecommunication, monitoring and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R3:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-003-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R4:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to have adequate monitoring systems with emphasis on cited criteria could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

There are six requirements in proposed IRO-008-2. Four of the six requirements were assigned a “Medium” VRF: Requirements R1, R2, R3, and R6. The other requirements were assigned a “High” VRF.

VRF for Proposed IRO-008-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an Operational Planning Analysis in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement and there are no comparable requirements to compare against. It is a coordination requirement in the operational planning timeframe so this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate an Operating Plan in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify entities of roles in Operating Plans in the operational planning timeframe, in and of itself, does not directly affect

the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure that a Real-time Assessment is performed at least once every 30 minutes could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. However, that requirement combines operations planning and Real-time. This requirement only applies to Real-time which in the belief of the SDT raises the VRF to High.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of roles in plans in the Real-time environment could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R15 which is assigned a Medium VRF. The requirements are similar in that proposed IRO-008-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3 is for Transmission Operators. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of when exceedances have been mitigated will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-010-2. Two of the requirements, Requirements R1 and R2, are assigned "Low" VRFs. Requirement R3 is assigned a "Medium" VRF.

VRF for Proposed IRO-010-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R2.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the data requested does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed IRO-014-3. Four of the requirements, Requirements R4, R5, R6, and R7, were assigned a "High" VRF. Requirements R1 and R3 were assigned a "Medium" VRF. Requirement R2 was assigned a "Low" VRF.

VRF for Proposed IRO-014-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-014-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have and implement the plans and procedures, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Low VRF. The requirement is for maintenance of plans, processes, and procedures. Hence, the designation of a Low VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to maintain the plans, processes, and procedures is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other Reliability Coordinators, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.2) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R7 which has a High VRF assignment.

The requirements are similar in that proposed TOP-001-3, Requirement R7 is for Transmission Operators and Balancing Authorities while proposed IRO-014-3, Requirement R9 is for Reliability Coordinators. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-017-1. All four of the requirements have been assigned a "Medium" VRF.

VRF for Proposed IRO-017-1, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a coordination process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Medium VRF. The requirement is for following the process described in proposed IRO-017-1, Requirement R1 which is assigned a Medium VRF. Hence, the designation of a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to follow the process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved TPL-001-4 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the assessments, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate solutions, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the “default” for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R4. Those VSLs are incremental. Therefore, the SDT assigned incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R4. Those VSLs are incremental. Therefore, the SDT assigned incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. Those VSLs tried to gradate the provision of data. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity supplies the data or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT has assigned these VSLs to be binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about complying with the Operating Instruction which has a binary Severe VSL in approved IRO-001-1.1. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about informing the Reliability Coordinator which has a single Moderate VSL in approved IRO-001-1.1. The SDT believes that such a failure should be classified as binary Severe under current guidelines.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R1. Those VSLs are gradated and the SDT has followed that pattern here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R8. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity has supplied the authority or it hasn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-003-2, Requirement R1. Those VSLs tried to gradate the degree of monitoring. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is doing the monitoring or it isn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R4. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is providing adequate monitoring facilities with the particular emphasis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-008-1, Requirement R1. Those VSLs tried to gradate the performance of the Operational Planning Analysis by the number of days in a month that it wasn't available. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity performs the analysis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no comparable requirement to compare against. The SDT believes that this is a binary situation where an entity performs the coordination activity or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs gradated the notification efforts. The SDT has followed a similar path and assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R2. Those VSLs gradated the performance of Real-time Assessments based on time increments. The SDT made a similar assignment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs partially gradated the notification elements. The SDT has followed a similar path but assigned a complete set of incremental VSLs here consistent with current accepted practice.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-001-3, Requirement R15. Those VSLs are set up as a binary Severe situation but that requirement only involves notifying one entity, the Reliability Coordinator. There are potentially many more entities involved with this requirement so the SDT has set up a gradated set of VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-014-1, Requirement R1. Those VSLs present an incremental approach and the SDT has continued that approach.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement with no comparable requirement to follow. There are a number of criteria cited for the requirement and this lends itself to an incremental approach for the VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs are presented in an incremental approach. Therefore, the SDT has assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.2. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs tried to gradate things but the only differential is whether evidence was provided or not – actions themselves are covered in Severe. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity develops a plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.1. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity implements the plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed TOP-001-3, Requirement R7. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to proposed IRO-005-3.1a, Requirement R6 which has gradated VSLs and the SFT has adopted that approach here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no similar requirement in the Reliability Standards. The responsible entity either follows the process or it doesn't. Attempting to increment the effort doesn't make sense. Therefore, this VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to approved TPL-001-4, Requirement R8. In that case, the VSLs are incremental. However, the responsible entities there are dealing with many other entities. In this case, the responsible entity is dealing only with Reliability Coordinators which makes an incremental approach unnecessary due to the much smaller number of involved entities. Therefore, the VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar in nature to proposed IRO-017-1, Requirement R1. The VSL has been assigned in a similar manner – binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Exhibit K

Summary of Development History and Complete Record of Development

Summary of Development History

Exhibit K: Summary of Development History

The development record for the following proposed Reliability Standards and proposed definitions is summarized below: TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1, and the definitions of "Operational Planning Analysis" and "Real-Time Assessment."

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit L.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for Project 2014-03 Revisions to TOP/IRO Reliability Standards was submitted on February 12, 2014. The SAR was posted from February 21, 2014 to March 24, 2014.

B. The First Posting – Formal Comment Period, Initial Ballots and Non-Binding Polls

The first drafts of the proposed TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 Reliability Standards, as well as the corresponding implementation plan and two new definitions, were posted for a 45-day public comment period from May 19, 2014 to July 2, 2014 with an initial ballot conducted from June

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).

23, 2014 to July 2, 2014. The ballot for these proposed Reliability Standards produced the following results:

- TOP-001-3 received a quorum of 82.59% and an approval of 30.99%,
- TOP-002-4 received a quorum of 82.85% and an approval of 62.18%,
- TOP-003-3 received a quorum of 82.85% and an approval of 63.07%,
- IRO-001-4 received a quorum of 82.32% and an approval of 68.57%,
- IRO-002-4 received a quorum of 82.59% and an approval of 36.94%,
- IRO-008-2 received a quorum of 82.59% and an approval of 47.87%,
- IRO-010-2 received a quorum of 82.85% and an approval of 60.26%,
- IRO-014-3 received a quorum of 82.85% and an approval of 61.67%,
- IRO-017-1 received a quorum of 82.06% and an approval of 57.94%,
- The Definitions received a quorum of 81% and an approval of 62.64%.
- The Implementation Plan received a quorum of 80.74% and an approval of 64.70%.

The non-binding polls were conducted from June 23, 2014 to July 2, 2014 and produced the following results:

- For TOP-001-3, 81.82% of those who registered to participate provided an opinion or an abstention, and 33.49% of those who provided an opinion indicated support for the VRFs and VSLs;
- For TOP-002-4, 82.11% of those who registered to participate provided an opinion or an abstention, and 55.78% of those who provided an opinion indicated support for the VRFs and VSLs;
- For TOP-003-3, 82.40% of those who registered to participate provided an opinion or an abstention, and 54.42% of those who provided an opinion indicated support for the VRFs and VSLs;
- For IRO-001-4, 82.11% of those who registered to participate provided an opinion or an abstention, and 55.56% of those who provided an opinion indicated support for the VRFs and VSLs;

- For IRO-002-4, 82.52% of those who registered to participate provided an opinion or an abstention, and 39.46% of those who provided an opinion indicated support for the VRFs and VSLs;

- For IRO-008-2, 82.11% of those who registered to participate provided an opinion or an abstention, and 47.09% of those who provided an opinion indicated support for the VRFs and VSLs;

- For IRO-010-2, 82.11% of those who registered to participate provided an opinion or an abstention, and 55.14% of those who provided an opinion indicated support for the VRFs and VSLs;

- For IRO-014-3, 82.11% of those who registered to participate provided an opinion or an abstention, and 52.41% of those who provided an opinion indicated support for the VRFs and VSLs; and,

- For IRO-017-1, 81.52% of those who registered to participate provided an opinion or an abstention, and 56.99% of those who provided an opinion indicated support for the VRFs and VSLs.

There were 71 sets of comments from approximately 186 individuals from approximately 136 companies representing all 10 industry segments. The standard drafting team considered stakeholder comments and made the following observations and non-substantive modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

C. The Second Posting – Formal Comment Period, Additional Ballots and Non-Binding Polls

The second drafts of the proposed TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 Reliability Standards were posted for a 45-day public comment period from August 6, 2014 to September 19, 2014 with additional ballots conducted from September 10, 2014 to September 19, 2014. The ballots for the second draft of these proposed Reliability Standards produced the following results:

- TOP-001-3 received a quorum of 85.49% and an approval of 48.73%,

- TOP-002-4 received a quorum of 85.22% and an approval of 78.87%,
- TOP-003-3 received a quorum of 86.28% and an approval of 87.03%,
- IRO-001-4 received a quorum of 85.75% and an approval of 76.12%,
- IRO-002-4 received a quorum of 84.96% and an approval of 74.23%,
- IRO-008-2 received a quorum of 84.96% and an approval of 75.67%,
- IRO-010-2 received a quorum of 85.22% and an approval of 85.49%,
- IRO-014-3 received a quorum of 84.96% and an approval of 75.69%,
- IRO-017-1 received a quorum of 85.22% and an approval of 78.67%.
- The Definitions received a quorum of 83.11% and an approval of 93.34%.
- The Implementation Plan received a quorum of 83.91% and an approval of 90.13%.

The non-binding polls were conducted from September 10, 2014 to September 19, 2014 and produced the following results:

- For TOP-001-3, 86.51% of those who registered to participate provided an opinion or an abstention, and 53.45% of those who provided an opinion indicated support for the VRFs and VSLs,
- For TOP-002-4, 86.51% of those who registered to participate provided an opinion or an abstention, and 73.30% of those who provided an opinion indicated support for the VRFs and VSLs,
- For TOP-003-3, 86.51% of those who registered to participate provided an opinion or an abstention; 79.30% of those who provided an opinion indicated support for the VRFs and VSLs,
- For IRO-001-4, 85.34% of those who registered to participate provided an opinion or an abstention, and 74.01% of those who provided an opinion indicated support for the VRFs and VSLs,
- For IRO-002-4, 85.04% of those who registered to participate provided an opinion or an abstention, and 69.69% of those who provided an opinion indicated support for the VRFs and VSLs,

- For IRO-008-2, 85.34% of those who registered to participate provided an opinion or an abstention, and 69.39% of those who provided an opinion indicated support for the VRFs and VSLs,

- For IRO-010-2, 85.63% of those who registered to participate provided an opinion or an abstention; 83.78% of those who provided an opinion indicated support for the VRFs and VSLs,

- For IRO-014-3, 85.63% of those who registered to participate provided an opinion or an abstention, and 78.61% of those who provided an opinion indicated support for the VRFs and VSLs,

- For IRO-017-1, 86.22% of those who registered to participate provided an opinion or an abstention; 74.19% of those who provided an opinion indicated support for the VRFs and VSLs.

There were 59 sets of comments from 166 individuals from approximately 95 companies representing 8 of the 10 industry segments. The standard drafting team considered stakeholder comments and made the following observations and non-substantive modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

D. Final Ballots

Proposed Reliability Standards IRO-001-4, IRO-002-4 and IRO-010-2 were posted for a 10-day final ballot period from October 10, 2014 through October 20, 2014, as well as an additional final ballot posted from October 10, 2014 through October 22, 2014 for proposed Reliability Standards TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3 and IRO-017-1. The non-binding Polls for TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3 and IRO-017-1 were extended an additional day to reach quorum. The final ballots for all of these proposed Reliability Standards produced the following results:

- TOP-002-4 received a quorum of 89.71% and an approval of 84.76%,

- TOP-003-3 received a quorum of 90.50% and an approval of 86.55%,

- IRO-001-4 received a quorum of 90.77% and an approval of 82.64%,
- IRO-002-4 received a quorum of 89.97% and an approval of 85.96%,
- IRO-008-2 received a quorum of 89.71% and an approval of 83.73%,
- IRO-010-2 received a quorum of 89.97% and an approval of 86.22%,
- IRO-014-3 received a quorum of 89.71% and an approval of 89.88%,
- IRO-017-1 received a quorum of 89.97% and an approval of 82.58%,
- The Definitions received a quorum of 88.39% and an approval of 94.07%.
- The Implementation Plan received a quorum of 88.39% and an approval of 91.84%.

The non-binding polls produced the following results:

- For TOP-002-4, 78.89% of those who registered to participate provided an opinion or an abstention, and 86.77% of those who provided an opinion indicated support for the VRFs and VSLs,
- For TOP-003-3, 78.30% of those who registered to participate provided an opinion or an abstention; 89.29% of those who provided an opinion indicated support for the VRFs and VSLs,
- For IRO-008-2, 78.59% of those who registered to participate provided an opinion or an abstention, and 85.88% of those who provided an opinion indicated support for the VRFs and VSLs,
- For IRO-014-3, 78.59% of those who registered to participate provided an opinion or an abstention, and 91.33% of those who provided an opinion indicated support for the VRFs and VSLs,
- For IRO-017-1, 78.89% of those who registered to participate provided an opinion or an abstention; 92.18% of those who provided an opinion indicated support for the VRFs and VSLs.

E. Authorization of Waiver from the NERC Standard Processes Manual

On October 9, 2014, the NERC Standards Committee approved waivers to the Standard Processes Manual to shorten an additional comment and ballot period for TOP-001-3 from 45 days to 30 days, and to shorten the final ballot for TOP-001-3 from ten days to seven days. The purpose of the waiver was to assist NERC in meeting a delivery date to the Commission for all of the proposed Reliability Standards.

F. The Third Posting – Formal Comment Period, Additional Ballot and Non-Binding Poll

The third draft of the proposed TOP-001-3 was posted for a 30-day formal comment period and additional ballot from October 10, 2014 to November 10, 2014 with an additional ballot conducted from November 4, 2014 to November 10, 2014. The ballot for the third draft of this standard received a 78.36% quorum and an approval of 60.21%. The non-binding poll for TOP-001-3 was conducted from November 4, 2014 to November 10, 2014 and 79.18% of those who registered to participate provided an opinion or an abstention; 63.33% of those who provided an opinion indicated support for the VRFs and VSLs.

There were 47 sets of comments from approximately 133 individuals from approximately 100 companies representing all 10 industry segments. The standard drafting team considered stakeholder comments and made the following observations and non-substantive modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

G. The Fourth Posting-Formal Comment Period, Ballot and Non-Binding Polls

The fourth draft of the proposed TOP-001-3 was posted for a 35-day public comment period and additional ballot from December 29, 2014 to January 7, 2015 with a ballot conducted from December 3, 2014 to January 7, 2015. The ballot for the third draft of this standard received a quorum of 80.47% and an approval of 72.43%. The non-binding poll for TOP-001-3 was conducted from December 29, 2014 to January 7, 2015 and 79.47% of those who registered to participate provided an opinion or an abstention; 73.58% of those who provided an opinion indicated support for the VRFs and VSLs.

There were 40 sets of comments from approximately 112 individuals from approximately 78 companies representing 9 of the 10 industry segments. The standard drafting team considered stakeholder comments and made the following observations and non-substantive modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

H. Final Ballot

Proposed Reliability Standard TOP-001-3 was posted for a 7-day final ballot, in accordance with the approved waiver, from January 15, 2015 through January 21, 2015. TOP-001-3 received a quorum of 84.70% and an approval of 72.69%.

I. Board of Trustees Adoption

The NERC Board of Trustees adopted the proposed Reliability Standards and definitions on November 13, 2014, with the exception of TOP-001-3, which was adopted on February 12, 2015.

Complete Record of Development

Program Areas & Departments > Standards > Project 2014-03 Revisions to TOP and IRO Standards

Project 2014-03 Revisions to TOP and IRO Standards

Related Files | Project 2007-03 Archive | Project 2006-06 Archive

Status:
A Final ballot for **TOP-001-3 - Transmission Operations** concluded at **8 p.m. Eastern on Wednesday, January 21, 2015**. Voting results can be accessed via the links below. The standard will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Board Adopted: November 13, 2014 - TOP-001-3, TOP-002-4, TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1, definitions of Real-time Assessment and Operating Planning Analysis, and the Implementation Plan.

Filed with FERC:

Order Effective:

Enforcement Date:

Purpose/Industry Need:
The primary goal of Project 2014-03 Revisions to TOP/IRO Reliability Standards is to address the concerns identified in the NOPR proposing to remand IRO standards developed in Project 2006-06 Reliability Coordination and TOP standards developed in Project 2007-03 Real-time Operations.

Background:
On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the “TOP Standards”) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the “IRO Standards”) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.” For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits (“SOLs”), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **TOP-001-3** – Transmission Operations Clean **(212)** | Redline to Last Posting **(213)** Implementation Plan **(214)** **Supporting Documents:** SAR **(215)** Notice of Waiver Request **(216)** Mapping Document **(217)**	Final Ballot Info>> **(222)** Vote>> (Closed)	01/15/15 - 01/21/15	Summary>> **(223)** Ballot Results>> **(224)**	

White Paper on Treatment of SOLs Clean **(218)** | Redline to Last Posting **(219)** Summary of NOPR Issues Clean **(220)** | Redline to Last Posting **(221)**				
Draft 4 **TOP-001-3** – Transmission Operations Clean **(187)** | Redline to Last Posting **(188)** Implementation Plan **(189)** **Supporting Documents:** Unofficial Comment Form (Word) **(190)** Notice of Waiver Request **(191)** SAR **(192)** Mapping Document **(193)** White Paper on Treatment of SOLs Clean **(194)** | Redline to Last Posting **(195)** Summary of NOPR Issues Clean **(196)** | Redline to Last Posting **(197)** Consideration of 2011 SW Outage Report Recommendations Clean **(198)** | Redline to Last Posting **(199)** Consideration of Issues and Directives **(200)** Consideration of IERP Recommendations and OCEC Review of Them **(201)** VRF/VSL Justification Clean **(202)** | Redline to Last Posting **(203)** **Draft RSAWs** IRO-008-2 Clean | Redline to Last Posting	Additional Ballot and Non-Binding Poll Updated Info>> **(204)** Info>> **(205)** Vote>> (Closed)	12/29/14 – 1/7/15	Summary>> **(207)** Ballot Results>> **(208)** Non-Binding Poll Results>> **(209)**	Consideration of Comments>> **(211)**
	Comment Period Info>> **(206)** Submit Comments>> (Closed) Due to several comments from the Standards Committee (SC) regarding the posting end date of TOP-001-3 being close to the end of the holiday period, the SC has authorized extending the posting of TOP-001-3 one day to Wednesday, January 7, 2015.	12/3/14 – 1/7/15	Comments Received>> **(210)**	

TOP-001-3 Clean | Redline to Last Posting				
Please send RSAW Feedback to: RSAWfeedback@nerc.net	12/9/14 - 1/7/15			
Draft 3 **TOP-001-3** – Transmission Operations Clean **(166)** | Redline to Last Posting **(167)** **Supporting Documents** Unofficial Comment Form (Word) **(168)** Notice of Waiver Request **(169)** SAR **(170)** Mapping Document **(171)** White Paper on Treatment of SOLs Clean **(172)** | Redline to Last Posting **(173)** Summary of NOPR Issues **(174)** Consideration of 2011 SW Outage Report Recommendations **(175)** Consideration of Issues and Directives **(176)** Consideration of IERP Recommendations and OCEC Review of Them **(178)** TOP-001-3 VRF/VSL Justification **(179)** **Draft RSAWs** IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1 TOP-001-3 TOP-002-4	Additional Ballot and Non-Binding Poll Info>> **(180)** Vote>> (Closed)	11/4/14 - 11/10/14	Summary>> **(182)** Ballot Results>> **(183)** Non-Binding Poll Results>> **(184)**	Consideration of Comments>> **(186)**
	Comment Period Info>> **(181)** Submit Comments>> (Closed)	10/10/14 - 11/10/14	Comments Received>> **(185)**	
	Please send RSAW Feedback to: RSAWfeedback@nerc.net	10/16/14 - 11/10/14		

TOP-003-3				
TOP-002-4 – Operations Planning Clean **(143)** | Redline to Last Posting **(144)** **TOP-003-3** – Operational Reliability Data Clean **(145)** | Redline to Last Posting **(146)** **IRO-008-2** – Reliability Coordinator Operational Analyses and Real-time Assessments Clean **(147)** | Redline to Last Posting **(148)** **IRO-014-3** — Coordination Among Reliability Coordinators Clean **(149)** | Redline to Last Posting **(150)** **IRO-017-1** – Outage Coordination Clean **(151)** | Redline to Last Posting **(152)** **Supporting Documents** VRF/VSL Justification **(153)**	Final Ballots and Non-Binding Polls Info>> **(154)** Vote>> (Closed)	10/10/14 - 10/22/14 (Non-Binding Polls extended an additional day to reach quorum)	Summary>> **(155)** Ballot Results TOP-002-4>> **(156)** TOP-003-3>> **(157)** IRO-008-2>> **(158)** IRO-014-3>> **(159)** IRO-017-1>> **(160)** Non-Binding Poll Results TOP-002-4>> **(161)** TOP-003-3>> **(162)** IRO-008-2>> **(163)** IRO-014-3>> **(164)** IRO-017-1>> **(165)**	
IRO-001-4 – Reliability Coordination – Responsibilities Clean **(128)** | Redline to Last Posting **(129)** **IRO-002-4** – Reliability Coordination — Monitoring and Analysis Clean **(130)** | Redline to Last Posting **(131)** **IRO-010-2** — Reliability Coordinator Data Specification and Collection Clean **(132)** | Redline to Last Posting **(133)** Two Definitions **(134)**	Final Ballots Info>> **(136)** Vote>> (Closed)	10/10/14 - 10/20/14	Summary>> **(137)** Ballot Results IRO-001-4>> **(138)** IRO-002-4>> **(139)** IRO-010-2>> **(140)** 2 Definitions>> **(141)** Implementation Plan>> **(142)**	

Implementation Plan **(135)**				
Draft 2 Standards **TOP-001-3** – Transmission Operations Clean **(69)** | Redline to Last Posting **(70)** **TOP-002-4** – Operations Planning Clean **(71)** | Redline to Last Posting **(72)** **TOP-003-3** – Operational Reliability Data Clean **(73)** | Redline to Last Posting **(74)** **IRO-001-4** – Reliability Coordination – Responsibilities Clean **(75)** | Redline to Last Posting **(76)** **IRO-002-4** – Reliability Coordination — Monitoring and Analysis Clean **(77)** | Redline to Last Posting **(78)** **IRO-008-2** – Reliability Coordinator Operational Analyses and Real-time Assessments Clean **(79)** | Redline to Last Posting **(80)** **IRO-010-2** — Reliability Coordinator Data Specification and Collection Clean **(81)** | Redline to Last Posting **(82)** **IRO-014-3** — Coordination Among Reliability Coordinators Clean **(83)** | Redline to Last Posting **(84)** **IRO-017-1** – Outage Coordination Clean **(85)** | Redline to Last Posting **(86)** Two Definitions Clean **(87)** | Redline to Last Posting **(88)** Implementation Plan Clean **(89)** | Redline to Last Posting **(90)** **Supporting Documents** SAR **(91)** Mapping Document **(92)** White Paper on Treatment of SOLs Clean **(93)** | Redline to Last Posting **(94)** Summary of NOPR Issues **(95)** Consideration of 2011 SW Outage Report Recommendations **(96)** Consideration of Issues and Directives **(97)**	Additional Ballots and Non-Binding Polls Updated Info>> **(102)** Info>> **(103)** Vote>> (Closed)	9/10/14 - 9/19/14	Summary>> **(105)** Ballot Results: TOP-001-3>> **(106)** TOP-002-4>> **(107)** TOP-003-3>> **(108)** IRO-001-4>> **(109)** IRO-002-4>> **(110)** IRO-008-2>> **(111)** IRO-010-2>> **(112)** IRO-014-3>> **(113)** IRO-017-1>> **(114)** Two Definitions>> **(115)** Implementation Plan>> **(116)** Non-Binding Poll Results: TOP-001-3>> **(117)** TOP-002-4>> **(118)** TOP-003-3>> **(119)** IRO-001-4>> **(120)** IRO-002-4>> **(121)** IRO-008-2>> **(122)** IRO-010-2>> **(123)** IRO-014-3>> **(124)** IRO-017-1>> **(125)**	

Consideration of IERP Recommendations and OCEC Review of Them **(98)** Draft SAR for TPL-001-5 **(99)** VRF/VSL Justification **(100)** Unofficial Comment Form **(101)** **Draft RSAWs** IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1 TOP-001-3 TOP-002-4 TOP-003-3				

	Comment Period Info>> **(104)** Submit Comments>> (Closed)	8/6/14 - 9/19/14	Comments Received>> **(126)** Note: Several entities voted negative in a few ballots supporting comments made by the SERC OC. However, there were no comments submitted by the SERC OC. After NERC staff communicated with these entities, they submitted comments which are included at the end of the comments received report (above link)	Consideration of Comments>> **(127)**
		9/2/14 - 9/19/14		

	Please send RSAW Feedback to: RSAWfeedback@nerc.net (Closed)			
Draft 1 Standards **TOP-001-3** – Transmission Operations **(22)** **TOP-002-4** – Operations Planning **(23)** **TOP-003-3** – Operational Reliability Data **(24)** **IRO-001-4** – Reliability Coordination - Responsibilities **(25)** **IRO-002-4** – Reliability Coordination — Monitoring and Analysis **(26)** **IRO-008-2** – Reliability Coordinator Operational Analyses and Real-time Assessments **(27)** **IRO-010-2** — Reliability Coordinator Data Specification and Collection **(28)** **IRO-014-3** — Coordination Among Reliability Coordinators **(29)** **IRO-017-1** – Outage Coordination **(30)** Two Definitions **(31)** Implementation Plan **(32)** **Supporting Documents**	Ballots and Non-Binding Polls Updated Info>> **(43)** Info>> **(44)** Vote>> (Closed)	6/23/14 - 7/2/14	Summary>> **(46)** Ballot Results: TOP-001-3>> **(47)** TOP-002-4>> **(48)** TOP-003-3>> **(49)** IRO-001-4>> **(50)** IRO-002-4>> **(51)** IRO-008-2>> **(52)** IRO-010-2>> **(53)** IRO-014-3>> **(54)** IRO-017-1>> **(55)** Two Definitions>> **(56)** Implementation Plan>> **(57)** Non-Binding Poll Results: TOP-001-3>> **(58)**	

SAR Clean **(33)** | Redline to Last Posting **(34)** Mapping Document **(35)** Mapping Document **(36)** UPDATED 6/6/2014 to add IRO-004-2 White Paper on Treatment of SOLs **(37)** Summary of NOPR Issues **(38)** Consideration of 2011 SW Outage Report Recommendations **(39)** Consideration of Issues and Directives **(40)** Consideration of IERP Recommendations **(41)** Unofficial Comment Form **(42)**			TOP-002-4>> **(59)** TOP-003-3>> **(60)** IRO-001-4>> **(61)** IRO-002-4>> **(62)** IRO-008-2>> **(63)** IRO-010-2>> **(64)** IRO-014-3>> **(65)** IRO-017-1>> **(66)**	
Draft RSAWs IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1 TOP-001-3 TOP-002-4 TOP-003-3	Comment Period Info>> **(45)** Submit Comments>> (Closed)	5/19/14 - 7/2/14	Comments Received>> **(67)**	Consideration of Comments>> **(68)**
	RSAW Info>> (Closed)	6/20/14 - 7/2/14		
	Join Ballot Pool>> (Closed) Please note: To avoid the inconvenience for the industry to join 20 ballot pools, we have set up one for the ballots on the standards and one for the non-binding polls. Once the ballot pools close, individual ballots will be created by carrying over the members of the ballot pools. There will be a separate ballot for each of the 9 standards, the definitions, implementation plan and 9 non-binding polls	5/19/14 - 6/17/14		
Technical Conference Slides **(15)** Technical Conference Recap Notes **(16)** Unofficial Comment Form (Word) **(17)**	Informal Comment Period Info>> **(20)**	3/11/14 – 3/24/14	Comments Received >> **(21)**	

FERC NOPR **(18)** NERC Motion to Defer Action **(19)**	Submit Comments>> (Closed)			
SAR **(1)** **Supporting Documents** Unofficial Comment Form (Word) **(2)** TOP-001-2 Transmission Operations **(3)** TOP-002-3 Operations Planning **(4)** TOP-003-2 Operational Reliability Data **(5)** IRO-001-3 Responsibilities and Authorities **(6)** IRO-002-3 Analysis Tools **(7)** IRO-005-4 Current Day Operations **(8)** IRO-014-2 Coordination Among Reliability Coordinators **(9)** FERC NOPR **(10)** NERC Motion to Defer Action **(11)**	Comment Period Updated Info>> (correcting "informal" to "formal" comment period) **(12)** Info>> **(13)** Submit Comments>> (Closed)	2/21/14 – 3/24/2014		Consideration of Comments>> **(14)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards. On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards. On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the suggestions from the Independent Expert Review Project will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards filed under Projects 2007-03 and 2006-06 to address concerns expressed in the NOPR a. Use the inputs from technical conferences to advise actions 2. Consider the comments and suggestions in the Independent Expert Review Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 5. Address the following directive from Order 693, paragraph 1855 so that all monitoring responsibilities for the Reliability Coordinator are included in the IRO family of standards: *"Since a reliability coordinator is the highest level of authority overseeing the reliability of the*

SAR Information
Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."
6. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner

Reliability and Market Interface Principles	
	to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5	Needs to be reviewed for language and terminology consistency with revisions made in this project

Related Standards	
IRO-008-1	
IRO-009-1	
IRO-010-1a	
IRO-015-1	
IRO-016-1	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the definition. The electronic comment form must be completed by **March 24, 2014**.

All documents and information about this project are available on the project page. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information - Project 2014-03 Revisions to TOP/IRO Reliability Standards

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addressed three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR announced the Commission's intent to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

As explained in the motion, NERC will hold two technical conferences (one in the East and one in the West) to identify and assess concerns regarding the TOP and IRO Standards identified n the NOPR, such as the monitoring of SOLs, unknown operating states, and outage coordination. Concurrently, NERC will work with the Standards Committee to re-formulate a standard drafting team to begin development work on revisions to the proposed standards, which would be informed by the technical conferences.

Additionally, in response to the concerns noted by the Commission in the NOPR on the development of a minimum set of analytical tools (analysis and monitoring capabilities) to ensure that Reliability Coordinators and Transmission Operators have the tools it needs to perform its functions, NERC will continue development of Reliability Standards that address Real-Time Tools as they relate to the proposed TOP and IRO standards, which could either continue to be included as part of Project 2009-02, Real-time Monitoring and Analysis Capabilities, or in revisions to the proposed TOP and IRO standards.

Links to the relevant files and project pages are included here for reference:

[NERC Petition on TOP Standards]

[NERC Petition on IRO Standards]

[FERC NOPR]

[NERC Motion to Defer Action]

[Project 2009-02 Real-time Monitoring and Analysis Capabilities project page]

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the scope and contents of the SAR? If not, please provide specific comments and suggestions for SDT consideration.

   ☐ Yes
   ☐ No
   Comments:

2. Are you aware of any regional variances associated with approved NERC Reliability Standards that will be needed as a result of this project? If yes, please identify the Regional Variance.

   ☐ Yes
   ☐ No
   Comments:

3. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

   ☐ Yes
   ☐ No
   Comments:

4. Are there any other concerns with this SAR?

   ☐ Yes
   ☐ No
   Comments:

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility

Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of

	Lower	Moderate	High	Severe
				exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	May 9, 2012	Adopted by Board of Trustees; Revisions pursuant to Project 2007-03	Revised

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TOP-001-2 — Transmission Operations

United States

Standard	Requirement	Enforcement Date	Inactive Date
TOP-001-2	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Operations Planning**
2. **Number:** TOP-002-3
3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.
4. **Applicability**

   4.1. Transmission Operator.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six-month period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the	The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and	The Transmission Operator did not notify three NERC-registered entities, or more than 10% and	The Transmission Operator did not notify four or more NERC-registered entities, or more

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	May 9, 2012	Changes pursuant to Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TOP-002-3 — Operations Planning

United States

Standard	Requirement	Enforcement Date	Inactive Date
TOP-002-3	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. Title: **Operational Reliability Data**

2. Number: TOP-003-2

3. Purpose: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. Applicability

4.1. Transmission Operator.

4.2. Balancing Authority.

4.3. Generator Owner.

4.4. Generator Operator.

4.5. Interchange Authority.

4.6. Load-Serving Entity.

4.7. Transmission Owner.

4.8. Distribution Provider.

5. Effective Date: All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	May 9, 2012	Changes pursuant to Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TOP-003-2 — Operational Reliability Data

United States

Standard	Requirement	Enforcement Date	Inactive Date
TOP-003-2	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title: Reliability Coordination – Responsibilities and Authorities**
2. **Number:** IRO-001-3
3. **Purpose:** To establish the authority of Reliability Coordinators to direct other entities to prevent an Emergency or Adverse Reliability Impacts to the Bulk Electric System.
4. **Applicability**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Generator Operator
   - **4.5.** Distribution Provider
5. **Effective Date:** The first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Reliability Coordinator shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact. *[Violation Risk Factor: High][Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's direction unless compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform as directed in accordance with Requirement R2. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

C. Measures

M1. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it had the authority to take action or direct action, which could have included issuing Reliability Directives, to prevent identified events or mitigate the magnitude or duration of actual events that resulted in an Emergency or Adverse Reliability Impact within its Reliability Coordinator Area. (R1.)

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's direction, unless the direction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's direction. (R2.)

M3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed the Reliability Coordinator of its inability to perform as directed in accordance with Requirement R2. (R3.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1shall retain voice recordings for the most recent 90 calendar days or documentation for the most recent 12 calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90 calendar days or documentation for the most recent 12 calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Reliability Coordinator failed to take action or direct actions, to prevent an identified event that resulted in an Emergency or Adverse Reliability Impact. OR The Reliability Coordinator failed to take action or direct actions to mitigate the magnitude or duration of an event that resulted in an Emergency or Adverse Reliability Impact.
R2	N/A	N/A	N/A	The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider did not comply with the Reliability Coordinator's direction, and compliance with the direction could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	N/A	N/A	N/A	The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider failed to inform its Reliability Coordinator upon recognition of its inability to perform as directed.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Approved by FERC — Effective Date	New
1	May 19, 2011	Replaced Levels of Noncompliance with FERC-approved VSLs	VSL Order
2	To be determined	Retired Requirement R7 to eliminate redundancy with IRO-014-2, Requirement R1.	Project 2006-06
3	TBD	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Revised the standard and retired six requirements (R1, R2, R4, R5, R6, and R9). Requirement R3 becomes the new R1 and R8 becomes the new R2 and R3.	Project 2006-06
3	August 16, 2012	Adopted by Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-001-3 — Reliability Coordination - Responsibilities and Authorities

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-001-3	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Reliability Coordination – Analysis Tools**

2. **Number:** IRO-002-3

3. **Purpose:** To ensure that Reliability Coordinators provide their System Operators with authority with respect to analysis tool outages and to have procedures to mitigate effects of analysis tool outages.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:** In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

B. Requirements

R1. Each Reliability Coordinator shall provide its System Operators with the authority to approve, deny or cancel planned outages of its own analysis tools. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

R2. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve, deny or cancel planned outages of its own analysis tools. (R1)

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that that the Reliability Coordinator has procedures in place to mitigate the effects of analysis tool outages. (R2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity is the Compliance Enforcement Authority except where the Reliability Coordinator works for the Regional Entity. Where the Reliability Coordinator works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1 and R2 and Measures M1 and M2.

o If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

o The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Violation Severity Levels				
R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve, deny or cancel planned outages of its own analysis tools.
R2	N/A	N/A	N/A	The Reliability Coordinator failed to have a procedure to mitigate the effects of analysis tool outages.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1	Revised as part of IROL Project
2	October 17, 2008	Adopted by NERC Board of Trustees	IROL Project
2	March 23, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	
3	August 4, 2011	Retired R1-R8 under Project 2006-06.	Project 2006-06
3	August 4, 2011	Adopted by the Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-002-3 — Reliability Coordination - Analysis Tools

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-002-3	All		

This standard has not yet been approved by the applicable regulatory authority.

Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**
2. **Number:** IRO-005-4
3. **Purpose:** To ensure that entities are notified when an expected or actual event with Adverse Reliability Impacts is identified.
4. **Applicability:**
   4.1. Reliability Coordinators.
5. **Effective Date:** In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

A. Requirements

R1. When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

R2. Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*

B. Measures

M1. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to dated operator logs, dated voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it notified all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when it identified an anticipated or actual condition with Adverse Reliability Impacts, within its Reliability Coordinator Area. (R1)

M2. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to dated operator logs, dated voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it notified all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area had been mitigated. (R2)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity is the Compliance Enforcement Authority except where the Reliability Coordinator works for the Regional Entity. Where the Reliability Coordinator works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator shall retain its evidence for the most recent 90 days for voice recordings or 12 months for other documentation for Requirements R1 and R2 and Measures M1 and M2.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records or for the time period specified above, whichever is longer.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator who identified an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area failed to issue an alert to one, but not all, impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.	The Reliability Coordinator who identified an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area failed to issue an alert to two, but not all, impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.	The Reliability Coordinator who identified an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area failed to issue an alert to three, but not all, impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.	The Reliability Coordinator who identified an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area failed to issue an alert to more than three impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. OR The Reliability Coordinator who identified an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area (in cases where there are less than three impacted entities).
R2	The Reliability Coordinator failed to notify one, but not all, impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	The Reliability Coordinator failed to notify two, but not all, impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	The Reliability Coordinator failed to notify three, but not all, impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	The Reliability Coordinator failed to notify more than three impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. OR The Reliability Coordinator failed to notify more all impacted

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated (in cases where there are less than three impacted entities).

D. Regional Differences

None identified.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 28, 2006	Added three items that were inadvertently left out to "Applicability" section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities.	Errata
1	February 7, 2006	BOT Approval	Revised
1	April 4, 2007	Regulatory Approval — Effective Date	New
2	November 1, 2006	BOT Approval	Revised under Missing Measures & Compliance Elements Project
2a	November 5, 2009	Interpretation approved by the Board of Trustees	Interpretation
3	October 17, 2008	Retired R2, R3, R5, R16, R17 and revised R9, R13, R14 to eliminate redundancy or conflicts with IRO standards IRO-009-1, and IRO-010-1	IROL Project – conforming changes
3	October 17, 2008	Adopted by the Board of Trustees	
3	March 23, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
3a	April 21, 2011	Added FERC approved Interpretation	
4	August 4, 2011	Retired R1-R11; revised R12	Project 2006-06
4	August 4, 2011	Adopted by the Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-005-4 — Reliability Coordination - Current Day Operations

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-005-4	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Coordination Among Reliability Coordinators**

2. **Number:** IRO-014-2

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date:** In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter that is 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter that is 12 months after Board of Trustees approval**.**

B. Requirements

R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Planning]*

1.1. Communications and notifications, including the mutually agreed to conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

1.2. Energy and capacity shortages.

1.3. Planned or unplanned outage information.

1.4. Control of voltage, including the coordination of reactive resources.

1.5. Coordination of information exchange to support reliability assessments.

1.6. Authority to act to prevent and mitigate system conditions which could cause Adverse Reliability Impacts to other Reliability Coordinator Areas.

1.7. Weekly conference calls

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Lower] [Time Horizon: Same Day Operations and Operations Planning]*

2.1. Review and update annually with no more that 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

R3. Each Reliability Coordinator shall make notifications and exchange reliability–related information with other Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1. *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations and Operations Planning]*

R4. Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement 1, Part 1.7) with other Reliability Coordinators within the same Interconnection. *[Violation Risk Factor: Lower][Time Horizon: Real-time Operations]*

R5. Each Reliability Coordinator, upon identification of an Adverse Reliability Impact, shall notify all other Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations and Real-time Operations]*

R6. During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations and Real-time Operations]*

R7. During those instances where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact, the Reliability Coordinator that identified the Adverse Reliability Impact shall develop an action plan to resolve the Adverse Reliability Impact. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same Day Operations and Real-time Operations]*

R8. During those instances where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact, each Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Adverse Reliability Impact unless such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same Day Operations and Real-time Operations]*

C. **Measures**

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Processes, and Operating Plans that require notifications, information exchange or the coordination of actions among impacted Reliability Coordinators for conditions or activities that impact other Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements. (R1)

M2. Each Reliability Coordinator shall have dated evidence that the Operating Procedures, Processes, and Plans that require one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) were:

2.1 Reviewed and updated annually with no more than 15 months between reviews.

2.2 Agreed to, in writing, by all the Reliability Coordinators required to take the indicated action(s).

2.3 Distributed within 30 days of an update to all Reliability Coordinators that are required to take the indicated action(s).

This evidence may include, but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions. (R2)

M3. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it made notifications and exchanged reliability–related information with impacted Reliability Coordinators in accordance with the Operating Procedures, Processes, or Plans identified in Requirement R1. (R3)

M4. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it participated in agreed upon (at least weekly) conference calls with other Reliability Coordinators within the same Interconnection. (R4)

M5. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an Adverse Reliability Impact, notified other Reliability Coordinators. (R5)

M6. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated under the assumption that the Adverse Reliability Impact existed during each instance where Reliability Coordinators disagreed on the existence of an Adverse Reliability Impact. (R6)

M7. Each Reliability Coordinator that identified an Adverse Reliability Impact shall have evidence and provide evidence that it developed an action plan during those instances where Reliability Coordinators disagreed on the existence of an Adverse Reliability Impact. This evidence may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation. (R7)

M8. Each impacted Reliability Coordinator shall have and provide evidence which may include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who has the identified the Adverse Reliability Impact when a Reliability Coordinator has identified an Adverse Reliability Impact and the impacted Reliability

Coordinators disagree on an action unless such actions would have violated safety, equipment, or regulatory or statutory requirements. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity is the Compliance Enforcement Authority except where the Reliability Coordinator works for the Regional Entity. Where the Reliability Coordinator works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.4. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1, R2, and Measures M1, M2.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement R3, R4, R5 and Measure M3, M4, M5.
- Each Reliability Coordinator shall retain 3 calendar years plus current calendar year of evidence for Requirements R6 through R8 and Measures M6 through M8.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, exchange of information or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.7.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, exchange of information or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.7.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, exchange of information or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.7.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, exchange of information or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability to address three or more of the topical areas identified in Parts 1.1 through 1.7.
R2	N/A	The Reliability Coordinator Operating Procedures, Operating Processes, or Operating Plans identified in R1 but failed to distribute these to all Reliability Coordinators that are required to take action.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in R1 but failed to obtain agreement from all Reliability Coordinators that are required to take action. OR Failed to review and update the Operating Procedures, Operating Processes, and Operating Plans identified in R1 annually.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in R1 but failed to review and update annually and obtain written agreement from all Reliability Coordinators that are required to take action and failed to distribute these to all Reliability Coordinators that are required to take action.
R3	N/A	N/A	The Reliability Coordinator failed to make notifications OR exchange reliability–related information with impacted Reliability Coordinators.	The Reliability Coordinator failed to make notifications AND exchange reliability–related information with impacted Reliability Coordinators.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	N/A	N/A	N/A	The Reliability Coordinator failed to participate in an agreed upon (at least weekly) conference call with impacted Reliability Coordinators within the same Interconnection.
R5	N/A	The Reliability Coordinator failed to notify one, but not all, of the impacted Reliability Coordinators upon identification of an Adverse Reliability Impact.	N/A	The Reliability Coordinator failed to notify more than one impacted Reliability Coordinators upon identification of an Adverse Reliability Impact. OR The Reliability Coordinator failed to notify the impacted Reliability Coordinator (when there is only one impacted Reliability Coordinator) upon identification of an Adverse Reliability Impact.
R6	N/A	N/A	N/A	The Reliability Coordinator failed to operate under the assumption that the Adverse Reliability Impact existed during an instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact.
R7	N/A	N/A	N/A	The Reliability Coordinator that identified the Adverse Reliability Impact failed to develop an action plan to resolve the Adverse Reliability Impact during an instance where Reliability Coordinators disagreed on the existence of an Adverse Reliability

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Impact.
R8	N/A	N/A	N/A	The Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identified the Adverse Reliability Impact during an instance where Reliability Coordinators disagreed on the existence of an Adverse Reliability Impact.

E. Regional Differences

None identified.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	January 20, 2006
1	February 7, 2006	Approved by BOT	Revised
1	April 4, 2007	Regulatory Approval — Effective Date	New
2	August 4, 2011	Revised per Project 2006-6; Revised existing requirements for clarity, retired R3 and R4 and incorporated requirements from IRO-015-1 and IRO-016-1 into this standard.	Revised
2	August 4, 2011	Adopted by Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-014-2 — Coordination Among Reliability Coordinators

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-014-2	All		

This standard has not yet been approved by the applicable regulatory authority.

145 FERC ¶ 61,158
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM13-12-000, RM13-14-000 and RM13-15-000]

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards

(Issued November 21, 2013)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to remand revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. In addition, the Commission proposes to approve NERC's proposed revisions to Reliability Standard TOP-006-3.

DATES: Comments are due **[Insert Date 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

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SUPPLEMENTARY INFORMATION:

145 FERC ¶ 61,158
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Monitoring System Conditions - Transmission Operations Reliability Standard	Docket No. RM13-12-000
Transmission Operations Reliability Standards	Docket No. RM13-14-000
Interconnection Reliability Operations and Coordination Reliability Standards	Docket No. RM13-15-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 21, 2013)

1. Pursuant to section 215(d) of the Federal Power Act (FPA),[1] the Commission proposes to remand revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. In addition, the Commission proposes to approve NERC's proposed revision to Reliability Standard TOP-006-3 concerning the monitoring role and notification obligation of reliability coordinators, balancing authorities and transmission operators. The Commission seeks comments on its proposals.

[1] 16 U.S.C. 824o(d) (2012).

2. NERC filed changes to the TOP Reliability Standards (Docket No. RM13-14-000) concurrently with its proposal to modify the IRO Reliability Standards (Docket No. RM13-15-000). NERC requests that the Commission process the two proposals together. In addition, NERC separately filed revisions to Reliability Standard TOP-006-3 (Docket No. RM13-12-000) that NERC proposes to become effective prior to the effective date of the revisions to the TOP Reliability Standards in Docket No. RM13-14-000. Because the proposed TOP and IRO Reliability Standards are interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involve similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the Commission addresses the three proposals together in this Notice of Proposed Rulemaking (NOPR).

3. NERC explains that the set of TOP Reliability Standards "address the important reliability goal of ensuring that the transmission system is operating within operating limits."[2] The TOP Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities of transmission operators. The set of IRO Standards apply to the responsibility and authority of reliability coordinators, the entities with the highest level of authority that are responsible for reliable operation of the bulk electric system, and have the wide-area view of the bulk

[2] NERC TOP Petition at 3.

electric system. The IRO Standards, which complement the TOP Standards, have the goal of ensuring that the bulk electric system is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.[3] Thus, together, the TOP and IRO Reliability Standards address matters that are fundamental to grid reliability as they pertain to the coordinated efforts to operate the bulk electric system in a reliable manner during real-time operations.

4. Based on our review of the NERC petitions, it appears that the proposed TOP and IRO Reliability Standards contain some improvements over the current standards. Specifically, the revised standards include organizational and administrative improvements that reduce redundancy and clarify the delineation between applicable entities with regard to certain tasks. The Commission appreciates efforts to clarify standards and reduce redundancies.[4] However, we are concerned that the changes in the proposed standards create reliability gaps in the standards that are critical to reliable operation of the Bulk-Power System. While NERC indicates that the revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements, we are concerned that NERC has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these

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[3] *See* NERC IRO Petition at 6.

[4] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

aspects in the proposed standards. One area of concern is that, unlike the currently-effective TOP Reliability Standards, there is no requirement in the proposed standards for transmission operators to plan and operate within all System Operating Limits (SOLs).[5] The provisions in the proposed TOP Reliability Standards that require transmission operators to operate only within a subset of SOLs offset the potential improvements. The Commission believes that NERC's proposal for the treatment of SOLs adversely impacts multiple requirements in the proposed TOP Reliability Standards. Moreover, as discussed herein, the Commission identifies other concerns that may need to be addressed in order not to create further reliability gaps. Section 215(d)(4) requires that the Commission remand to the ERO for further consideration a Reliability Standard "that the Commission disapproves in whole *or in part*."[6] Thus, notwithstanding the improvements mentioned above, the concern regarding the treatment of SOLs, and potentially other concerns discussed below, leads us to propose to remand the proposed TOP standards. In addition, given the interrelationship between the TOP and IRO Reliability Standards

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[5] NERC defines a SOL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits [pre- and post-Contingency] are based upon certain operating criteria. … "

[6] 16 U.S.C. 824o(d)(4) (2012) (emphasis added).

and that NERC requests that both sets of standards be addressed together,[7] we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.

5. In addition to the concerns regarding the treatment of SOLs, the Commission has identified a reliability gap in the IRO Reliability Standards and accordingly proposes to direct that NERC develop modifications in these standards to ensure that reliability coordinators continue to develop and implement comprehensive generation and transmission outage coordination processes.

6. Further, we discuss below additional issues regarding the proposed TOP and IRO Reliability Standards that require clarification or further explanation and technical justification. Depending on the explanations provided by NERC and other interested entities in their comments to this NOPR, additional Commission action may be appropriate, including directives that NERC must address in response to a final rule in this proceeding.

[7] NERC TOP Petition at 2 (stating that "simultaneous approval of both petitions by the Commission will help ensure a smooth transition and implementation of the proposed Reliability Standards for both the industry and the ERO.").

I. Background

7. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 initial Reliability Standards filed by NERC, including the existing TOP and IRO Reliability Standards.[8] In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards; however, none of the standards approved in Order No. 748 are at issue in this NOPR.[9]

A. NERC's TOP Petition (Docket No. RM13-14-000)

8. On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards.

[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

NERC also seeks approval of the implementation plan for the proposed TOP Reliability Standards and approval of the retirement of eight TOP and one PER Reliability Standards,[10] and to retire Requirements R2, R5, and R6 of Reliability Standard PRC-001-1.

9. NERC states that the proposed TOP Reliability Standards represent significant revision and improvement to the current set of enforceable Reliability Standards by upgrading the overall quality of the standards, eliminating gaps in the requirements, ambiguity, redundancies, and addressing Order No. 693 directives. NERC adds that the proposed TOP Reliability Standards are also more efficient than the currently-effective standards because they incorporate the necessary requirements from today's standards into three cohesive, comprehensive Reliability Standards "that are focused on achieving a specific result."[11] NERC states that the proposed TOP Reliability Standards, along with the proposed IRO Reliability Standards, will help to ensure better coordination for

[10] TOP-001-1a – (Reliability Responsibilities and Authorities); TOP-002-2.1b (Normal Operations Planning); TOP-003-1 (Planned Outage Coordination); TOP-004-2 (Transmission Operations); TOP-005-2a (Operational Reliability Information); TOP-006-2 (Monitoring System Conditions); TOP-007-0 (Reporting System Operating Limit and Interconnection Reliability Operating Limit Violations); TOP-008-1(Response to Transmission Limit Violations); and on Personnel Performance, Training, and Qualifications (PER) Reliability Standard, PER-001-0.2 (Operating Personnel Responsibility and Authority).

[11] NERC TOP Petition at 4, 11, 42. NERC explains that the corresponding changes in proposed Reliability Standard PRC-001-2 are administrative in nature and are limited to removal of three requirements in currently-effective Reliability Standard PRC-001-1 that are now addressed in proposed Reliability Standard TOP-003-2.

transmission operators and reliability coordinators to "plan and operate the interconnected Bulk Electric System in a synchronized manner to perform reliably under normal and abnormal conditions."[12]

10. NERC states that the proposed TOP Reliability Standards are a significant improvement from the currently-effective TOP Reliability Standards in three ways. First, NERC explains that the proposed TOP Reliability Standards "rais[e] the bar on system performance by mandating that all IROLs be resolved within the IROL T_v, which is a significant increase in performance over the existing Reliability Standards."[13] NERC indicates that the proposed TOP Reliability Standards adopt an approach "for operating within a subset of SOLs that more closely aligns with the original NERC Operating Guidelines."[14] Second, NERC states that it improved the proposed Reliability Standards by designating requirements to apply solely to transmission operators and removing several of the requirements applicable to reliability coordinators. NERC explains that it

[12] NERC TOP Petition at 9.

[13] NERC TOP Petition at 11. The Interconnection Reliability Operating Limit (IROL) T_v is defined in the NERC Glossary of Terms as: "The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes."

[14] NERC TOP Petition at 11. NERC states that "[p]rior to becoming the ERO, NERC guidelines for power system operation and accreditation were referred to as the NERC Operating Guidelines, for which compliance was strongly encouraged yet ultimately voluntary." *Id.* at n.23.

added requirements applicable to reliability coordinators to the proposed IRO Reliability Standards. Third, NERC states it consolidated "the necessary requirements from the eight existing TOP Reliability Standards into three cohesive, comprehensive Reliability Standards."[15] The specific revisions to the TOP Reliability Standards are as follows:

TOP-001-2 (Transmission Operations)[16]

11. In the TOP petition, NERC explains that the requirements of proposed Reliability Standard TOP-001-2 address the following matters: (1) transmission operator "Reliability Directives" (proposed Requirements R1 and R2); (2) emergencies and emergency assistance (proposed Requirements R3-R6); and (3) IROLs and SOLs (proposed Requirements R7-R11). Proposed Requirements R1 and R2 state:

> **R1.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.
>
> **R2.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

NERC states that proposed Requirement R1 recognizes the reliability need to give transmission operators the ability to issue Reliability Directives to various entities,

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[15] NERC TOP Petition at 11.

[16] The proposed TOP and IRO Reliability Standards are not attached to the NOPR. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket Nos. RM13-14 and RM13-15 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

subject to limited exceptions in cases where such actions would violate safety, equipment, regulatory, or statutory requirements. NERC explains that Requirement R2 requires entities receiving the directive from the transmission operator to inform the transmission operator in situations where an identified Reliability Directive cannot be performed. NERC explains that these requirements give transmission operators the authority to issue Reliability Directives when needed, but also provide them the flexibility to take different action in those situations where an entity notifies its transmission operator of its inability to comply with a Reliability Directive.[17]

12. With regard to emergencies and emergency assistance, NERC proposes Requirements R3 through R6:

> **R3.** Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.
>
> **R4.** Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.

[17] NERC TOP Petition at 12-13.

> **R6.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

NERC states that proposed Requirements R3, R5, and R6 apply to the coordination aspects of interconnected operation. NERC explains that proposed Requirement R3 requires a transmission operator to inform its reliability coordinators and other transmission operators of actual and anticipated emergencies based on its assessment of its "Operational Planning Analysis."[18] NERC states that, in situations "where emergency assistance is needed, proposed Requirement R4 requires that Transmission Operators render emergency assistance to other Transmission Operators when it is requested and available" and that proposed Requirement R5 "requires Transmission Operators to inform entities (Reliability Coordinators and other Transmission Operators) of operations that may adversely impact them."[19] According to NERC, this proposed requirement addresses the Order No. 693 directive to consider the need for the transmission operator to notify the reliability coordinator or the balancing authority when facilities are removed

[18] NERC defines an Operational Planning Analysis as "[a]n analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." NERC Glossary of Terms at 47.

[19] NERC TOP Petition at 14.

from service.[20] NERC states that proposed Requirement R6 requires balancing authorities and transmission operators to notify the reliability coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment.

13. With respect to treatment of SOLs and IROLs, NERC explains that the standard drafting team examined the requirements for SOLs and IROLs in the currently-effective TOP Reliability Standards to ensure whether they adequately addressed the handling of these limits. In particular, the standard drafting team was concerned that the transition from the NERC Operating Guidelines to the Version 0 standards had resulted in an incorrect emphasis on non-IROL SOLs as opposed to IROLs. The standard drafting team noted a discrepancy among the three currently-effective SOL/IROL-related requirements.[21] According to NERC, in Reliability Standards TOP-002-2a, Requirement R10 and TOP-004-2, Requirement R1, applicable entities are expected to plan and operate to meet all SOLs and IROLs, while in TOP-007-0, R1, entities are only instructed

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[20] NERC TOP Petition at 14 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1588).

[21] TOP-002-2a, Requirement R10: Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). TOP-004-2, Requirement R1: Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). TOP-007-0, Requirement R2: Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

to take action for IROLs. According to NERC, the standard drafting team concluded that the Version 0 standards did not accurately reflect what the operating policies stated. Nevertheless, the standard drafting team determined that non-IROL SOLs are still important. NERC explains that reliability risk to the system exists when the system is operating in conditions such that an IROL limit is exceeded for a time exceeding T_v. Consequently, NERC revised the requirements related to operating within limits by tying IROL actions to T_v. NERC proposes Requirements R7 through R11 to address the transmission operator's responsibilities over IROLs[22] or SOLs[23] that the transmission operator identifies as necessary to support reliability internal to its transmission operator area:

> **R7.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
>
> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**

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[22] NERC defines an IROL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."

[23] NERC defines a SOL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits [pre- and post-Contingency] are based upon certain operating criteria. … "

> **R9.** Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R10.** Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
>
> **R11.** Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

NERC explains that the responsibility for monitoring and handling IROLs is primarily given to the reliability coordinator, but the transmission operator has the primary responsibility to designate any SOLs that require special attention. NERC indicates that the delineation in the proposed TOP Reliability Standards with respect to operating within an identified IROL and in designating important SOLs is an important distinction in the proposed TOP Reliability Standards that is necessary for reliability.

14. NERC adds that the proposed TOP Reliability Standards include a requirement that provides for "the identification of a sub-set of non-IROL SOLs that are identified as important for local areas."[24] NERC indicates that the proposed requirements mandate exceedances of these non-IROL SOLs to be monitored and reported to the reliability coordinator, giving transmission operators "the ability to ensure that any non-IROL SOLs

[24] NERC TOP Petition at 19.

that are of concern to the transmission operator will be monitored to ensure local consequences are managed."[25]

15. NERC states that the "difference between non-IROL SOLs and IROLs is expressed in the difference between the consequences to the System (or impact to reliability) should unplanned perturbations of the System occur when the limit is being exceeded. For an IROL, the consequences are described as Cascading, uncontrolled separation, or instability."[26] NERC explains that the consequences of non-IROL SOLs are typically thought of in terms of equipment damage or total loss of an element and are restricted to a limited or local area. NERC states that the revised TOP requirements move the standards to where the NERC Operating Guidelines intended them to be and ensure that the reliability of the interconnected system will be maintained and even enhanced because system operators "will not be distracted from true reliability issues by local system issues."[27] NERC states that the impact of exceeding a non-IROL SOL will not result in an Adverse Reliability Impact.[28]

16. According to NERC, transmission operators may also identify and communicate to their reliability coordinator any of the non-IROL SOLs that are believed or anticipated

[25] *Id.* at 19-20.

[26] *Id.* at 19.

[27] NERC TOP Petition at 18.

[28] NERC TOP Petition at 18-19.

to have potential to develop into IROLs and, thus, to ensure that they too are monitored and managed. NERC also explains that, while non-IROL SOLs are similar to IROLs in that non-IROL SOLs must respect the ratings of equipment associated with the facilities to which the non-IROL SOL applies, there is no specific requirement established for a time exceedance similar to the T_v of an IROL. According to NERC, because T_v may be less than 30 minutes, T_v "mandates a tighter time frame for action than the 30-minute time that is mandated in the currently-effective standards, thereby improving reliability of the bulk power system."[29]

Proposed TOP-002-3 (Operations Planning)

17. NERC states that proposed Reliability Standard TOP-002-3 Requirements R1 through R3 require transmission operators to perform Operational Planning Analyses to ensure operations within IROLs and SOLs. The requirements for proposed Reliability Standard TOP-002-3 are as follows:

> **R1.** Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
>
> **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

[29] NERC TOP Petition at 18.

> **R3.** Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC explains that Requirement R1 requires transmission operators to have an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed any of its facility ratings or stability limits during anticipated normal and contingency event conditions. NERC also explains that Requirement R2 requires transmission operators to develop a plan that will help ensure they do not operate in excess of limits identified in the Operational Planning Analysis. NERC indicates that Requirement R3 requires that entities be notified if they are identified in the transmission operator's plans and that the notification should inform entities of their role in the plans.

18. According to NERC, requiring transmission operators to perform Operational Planning Analyses that incorporate normal and contingency situations for next-day operations while assuring appropriate limits are not violated assures that the transmission operators "will have a plan to follow during Real-time operations that accurately reflects the anticipated conditions of the day's operations, including the ability to deliver generation to Load."[30] NERC adds that Requirement R3 is similar to the coordination requirements established in proposed Reliability Standard TOP-001-2 by ensuring that all entities know their role in next-day operations.

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[30] NERC TOP Petition at 22.

Proposed TOP-003-2 (Operational Reliability Data)

19. NERC states that proposed Reliability Standard TOP-003-2, Requirements R1 through R5 were adapted for transmission operators and balancing authorities based on similar, Commission-approved requirements for reliability coordinators.[31] The proposed requirements include:

> **R1.** Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include:
>
> **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.
> **1.2.** A mutually-agreeable format.
> **1.3.** A periodicity for providing data.
> **1.4.** The deadline by which the respondent is to provide the indicated data.
>
> **R2.** Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring…
>
> **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification…shall satisfy the obligations of the documented specifications for data.

NERC states that the proposed requirements emphasize the need for transmission operators and balancing authorities to obtain all of the data they need for reliability purposes and mandate that entities that have this data timely provide it to the transmission operator and balancing authority. According to NERC, lack of adequate data for real-time operations and modeling have contributed to system incidents in the past, and the

[31] NERC TOP Petition at 23 (citing Reliability Standard IRO-010-1a.)

data specification concept will eliminate this problem by allowing transmission operators and balancing authorities to require entities to send them any required data.

NERC's Response to Order No. 693 Directives and Analysis of Southwest Outage Report

20. NERC indicates that its staff analyzed the recommendations from the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations ("2011 Southwest Outage Blackout Report") that apply to transmission operators and compared the recommendations to both the currently-effective TOP Reliability Standards and the proposed Reliability Standards.[32] The TOP Petition provides that, "[b]ased on this analysis, NERC staff believes that if entities complied with the proposed TOP Reliability Standards, the likelihood of such an event occurring would be significantly diminished."[33] NERC includes as Exhibit H a detailed report on this analysis, including the relevant 2011 Southwest Outage Blackout Report recommendations with an explanation of how the relevant recommendations would be addressed in the proposed TOP Reliability Standards.

21. The NERC TOP Petition includes a summary of nine Order No. 693 directives related to the proposed TOP Reliability Standards and NERC's responses to those directives in Exhibit I. NERC also explains that, rather than addressing two directives from Order No. 693 relating to minimum analysis and monitoring capabilities in the

[32] NERC TOP Petition at 6 and Exh. H.

[33] NERC TOP Petition at 6.

proposed TOP Reliability Standards and proposed IRO Reliability Standards, the standard drafting team chose to have them addressed by the Project 2009-02 Standard Drafting Team.[34] According to NERC, it "is developing a set of Reliability Standards in Project 2009-02, which is expected to be completed in 2014," that will establish requirements for the functionality, performance, and maintenance of real-time monitoring and analysis capabilities for reliability coordinators, transmission operators, generator operators, and balancing authorities for use by their system operators in support of reliable system operations.[35]

<u>TOP Implementation Plan</u>

22. NERC states that some of the proposed revisions to the TOP Reliability Standards are dependent on corresponding changes to proposed IRO Reliability Standards (IRO-001-3 and IRO-005-4) and to one Verification and Data Reporting of Generator Real and Reactive Power Capability Reliability Standard - MOD-025-2. NERC states that the proposed TOP Reliability Standards cannot be implemented until all three of the above standards have been implemented.

23. In its implementation plan, NERC also states that there "are no new definitions in the proposed set of standards" but the standard drafting teams for the TOP and IRO

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[34] One directive is applicable to Reliability Standard IRO-002 and is described in PP 905 and 906 of Order No. 693, and the second directive is applicable to Reliability Standard TOP-006 and is described in P 1660.

[35] NERC IRO Petition at 27.

projects have coordinated on a common definition of "Reliability Directive" and agreed that the IRO standard drafting team "would write the definition and post it for vetting by the industry." The definition is as follows:

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Further, the IRO-014-2 implementation plan indicates that a revised definition for "Adverse Reliability Impact" was approved by the NERC Board of Trustees on August 4, 2011; however, the petition does not discuss the merits of this change.[36] In addition, NERC does not discuss the impact of this revised definition on the overall body of Reliability Standards.

24. NERC requests that all requirements except proposed Reliability Standard TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter twelve months following applicable regulatory approval.[37] NERC also requests that Requirements R1 and R2 of proposed Reliability Standard TOP-003-2 become effective the first day of the first calendar quarter ten months following applicable

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[36] Adverse Reliability Impact (ARI) - Previous Definition - The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. ARI – Revised Definition – The impact of an event that results in the Bulk Electric System instability or Cascading.

[37] NERC also requests that the existing TOP Reliability Standards be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following applicable regulatory approval.

regulatory approval. NERC explains that the twelve month period is to allow for entities to update processes and train operators on the revised requirements, and the two month differential for proposed Reliability Standard TOP-003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.[38]

B. NERC's IRO Petition (Docket No. RM13-15-000)

25. Also on April 16, 2013, NERC submitted for Commission approval four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators).[39] NERC also requests approval of the implementation plan for the proposed IRO Reliability Standards, and approval of the retirement of six currently-effective Reliability Standards, effective at midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a final rule in this proceeding.[40] NERC indicates that its petition also addresses two

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[38] NERC TOP Petition, Exh. C at 2.

[39] NERC states that the NERC Board of Trustees approved a proposed Reliability Standard IRO-001-2 Reliability Standard on August 4, 2011, that was subsequently revised before it was filed at the Commission. The revision is designated as Reliability Standard IRO-001-3, was approved by the Board on August 16, 2012, and is included in this petition for approval. NERC IRO Petition at 4 n.5.

[40] NERC proposes to retire Reliability Standards IRO-001-1.1 (Responsibilities and Authorities); IRO-002-2 (Facilities); IRO-005-3a (Current Day Operations); IRO-014-1 (Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators); IRO-015-1 (Notifications and Information Exchange Between Reliability Coordinators); IRO-016-1 (Coordination of Real-time Activities Between Reliability Coordinators).

Order No. 693 directives associated with Reliability Standard IRO-005-1, but that it does not address a directive associated with Reliability Standard IRO-002-1 because this directive falls under the scope of Real-Time Tools Best Practices Task Force.

26. NERC identifies two "overall reliability benefits" of the proposed IRO Reliability Standards: (1) delineating a "clean division of responsibilities" between the reliability coordinator and transmission operator, giving the reliability coordinator authority to direct transmission operators to take actions to prevent or mitigate Interconnection Reliability Operating Limits (IROLs); and (2) "raising the bar" on IROL/SOL monitoring to focus on only those important to reliability. NERC also identifies four "improvements" reflected in the proposed IRO Reliability Standards, as follows:

- Interconnected bulk electric systems will be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
- Personnel responsible for planning and operating interconnected bulk electric systems will be trained, qualified, and have the responsibility and authority to implement actions.
- The security of the interconnected bulk electric systems will be assessed, monitored and maintained on a wide-area basis.
- Plans for emergency operation and system restoration … will be developed, coordinated, maintained and implemented.[41]

[41] NERC IRO Petition at 11.

<u>IRO-001-3 (Responsibilities and Authorities)</u>

27. NERC proposes to replace the nine currently-effective requirements of Reliability Standard IRO-001-1 with the following three requirements in proposed IRO-001-3:

> **R1.** Each Reliability Coordinator shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.
>
> **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's direction unless compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform as directed in accordance with Requirement R2.

NERC states that these requirements ensure that reliability coordinators "have the responsibility and authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact."[42] According to NERC, these proposed requirements "ensure that the responsibility and authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact is assigned to the Reliability Coordinator."[43]

[42] NERC IRO Petition at 12.

[43] NERC IRO Petition at 12-13.

28. NERC states that the changes to the proposed Reliability Standard IRO-001-3 are a result of the proposed retirement of the currently-effective Reliability Standard IRO-001-1.1, Requirement R7, which is now covered in proposed Reliability Standard IRO-014-2.[44] According to NERC, Reliability Standard IRO-014-2 will continue to ensure that both coordination agreements are in place to require that IROLs and SOLs are managed, and that system conditions that could cause Adverse Reliability Impacts are mitigated.

IRO-002-3 (Analysis Tools)

29. NERC proposes two new requirements pertaining to analytical tools and to retire Requirements R1 through R7 of currently-effective Reliability Standard IRO-002-2. The two proposed requirements provide:

> **R1.** Each Reliability Coordinator shall provide its System Operators with the authority to approve, deny or cancel planned outages of its own analysis tools.
>
> **R2.** Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

30. NERC states that the currently-effective requirements contain redundancies, which the proposed revision are intended to eliminate. NERC states that it revised Requirement R8 and incorporated it into proposed Requirements R1 and R2 of Reliability Standard

[44] Currently-effective Requirement R7 states: The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.

IRO-002-3. NERC also indicates that it is developing a set of Reliability Standards in Project 2009-02, that will establish requirements for the functionality, performance, and maintenance of real-time monitoring and analysis capabilities which affects Reliability Standard IRO-002.

<u>IRO-005-4 (Current Day Operations)</u>

31. NERC proposes the following two new requirements for proposed Reliability Standard IRO-005-4:

> **R1.** When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
>
> **R2.** Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated.

32. NERC states that proposed Reliability Standard IRO-005-4 is a result of eliminating redundancies between existing and proposed standards. NERC also states that the requirements are to "ensure that entities are notified when an expected or actual event with Adverse Reliability Impacts is identified."[45]

<u>IRO-014-2 (Coordination Among Reliability Coordinators)</u>

33. NERC proposes the eight requirements of Reliability Standard IRO-014-2 to replace the currently-effective Reliability Standards IRO-014-1, IRO-015-1 and

[45] NERC IRO Petition at 28.

IRO-016-1. NERC states that proposed Reliability Standard IRO-014-2 ensures that each reliability coordinator's operations are coordinated to avoid an Adverse Reliability Impact on other reliability coordinator areas and to preserve the reliability benefits of interconnected operations. Proposed Reliability Standard IRO-014-2 provides in part:

> **IRO-014-2 R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following:
>
> > **1.1.** Communications and notifications, including the mutually agreed to conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
> > **1.2.** Energy and capacity shortages.
> > **1.3.** Planned or unplanned outage information.
> > **1.4.** Control of voltage, including the coordination of reactive resources.
> > **1.5.** Coordination of information exchange to support reliability assessments.
> > **1.6.** Authority to act to prevent and mitigate system conditions which could cause Adverse Reliability Impacts to other Reliability Coordinator Areas.
> > **1.7.** Weekly conference calls.
>
> **R5.** Each Reliability Coordinator, upon identification of an Adverse Reliability Impact, shall notify all other Reliability Coordinators.
>
> **R6.** During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.
>
> **R7.** During those instances where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact, the Reliability Coordinator that identified the Adverse Reliability Impact shall develop an action plan to resolve the Adverse Reliability Impact.

34. NERC states that Requirement R1 is the same as the currently-effective requirement except for the addition of Part 1.7, which requires reliability coordinators to

have weekly conference calls. Additionally, while Requirement R1 of Reliability Standard IRO-014-1 addresses "Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability," NERC states that proposed Requirement R1 defines specific information that is to be included in the procedures, processes, and plans.

IRO Implementation Plan

35. NERC proposes as the effective date for Reliability Standard IRO-001-3, the first day of the second calendar quarter beyond the date that the standard is approved by the Commission. NERC states that this time will allow applicable entities adequate time to develop the documentation and other evidence necessary to exhibit compliance with the requirements. NERC proposes as the effective date for Reliability Standards IRO-002-3 and IRO-005-4 the first day of the first calendar quarter following the effective date of a final rule because the revisions are "to an existing mandatory and enforceable standard, applicable entities are already complying with the existing standard."[46]

36. For proposed Reliability Standard IRO-014-2, NERC proposes the first day of the first calendar quarter that is twelve months following the effective date of a final rule as the effective date. NERC states that, while the revisions to this Reliability Standard are to an existing mandatory and enforceable standard, "applicable entities should only have

[46] NERC IRO Petition, Exh. A at 8.

to make minor revisions to their Operating Plans, Operating Processes or Operating Procedures to show compliance."[47]

37. NERC also proposes retirement of the six IRO Reliability Standards, effective at midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a final rule.

C. Proposed Revisions to Reliability Standard TOP-006-3 (Docket No. RM13-12)

38. On April 4, 2013, NERC proposed revisions to Reliability Standard TOP-006-3 to divide the reporting responsibilities of balancing authorities and transmission operators into separate requirements. According to NERC, the proposed revisions clarify that transmission operators are responsible for monitoring and reporting available transmission resources, while balancing authorities are responsible for monitoring and reporting available generation resources. NERC states that this division is consistent with the roles and responsibilities of registered entities as set forth in NERC Reliability Functional Model.

39. NERC states that, as currently written, Requirement R1.2 could be interpreted as duplicating efforts to monitor and report the availability of generation and transmission resources. NERC explains that it specifically requires both transmission operators and balancing authorities to inform reliability coordinators and other affected transmission operators and balancing authorities of all transmission and generation resources available

[47] NERC IRO Petition, Exh. A at 8-9.

for use. To address these concerns, NERC revised Requirement R1.2 to limit a transmission operator's monitoring and notification obligations to transmission resources available for use. NERC created Requirement R1.3 to limit a balancing authority's monitoring and notification obligations to generation resources available for use. NERC explains that proposed Requirement R1.3 only requires balancing authorities to inform reliability coordinators of all generation resources available for use, and they are not required to report the availability of generation resources to transmission operators because transmission operators already receive this information from generator operators pursuant to currently effective Requirement R1.1. According to NERC, by defining the reporting channels from transmission operators and balancing authorities to reliability coordinators, reliability coordinators will receive necessary information in advance, as part of their operating tools, processes and procedures, to prevent and mitigate emergency operating situations in real and next day operations.

40. In addition, NERC proposes to modify currently-effective Requirement R3. According to NERC, while the currently-effective Requirement R3 requires reliability coordinators, transmission operators and balancing authorities to provide appropriate technical information concerning protective relays to their operating personnel, NERC states that it does not impose explicit geographical boundaries on the scope of this obligation. NERC indicates that revised Requirement R3 specifies that the relevant protective relays are those within these entities' respective reliability coordinator area, transmission operator area or balancing authority area.

41. NERC has proposed medium Violation Risk Factors (VRFs) for proposed TOP-006-3, Requirements R1.2, R1.3 and R3 because these three Requirements all ensure that critical reliability parameters are monitored in real-time. NERC also states that the proposed Violation Security Levels (VSLs) for Requirement R1.3 meet NERC's VSL guidelines. NERC requests that the revisions become effective on the first day of the first calendar quarter after applicable regulatory approval.

II. <u>Discussion</u>

42. Pursuant to section 215(d) of the FPA, we propose to remand NERC's proposed revisions to the TOP and IRO Reliability Standards (Docket Nos. RM13-14-000 and RM13-15-000). While we believe that NERC's approach of condensing the requirements and removing redundancies generally has merit, we are concerned that, unlike the currently-effective TOP Reliability Standards, there is no requirement in the proposed standards for transmission operators to plan and operate within all SOLs. Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area. As described below, this was a problem during the Southwest Outage when the loss of a 500 kV line in Arizona Public Service's area overloaded equipment, which ultimately resulted in a cascade outage

leaving approximately 2.7 million customers without power.[48] The provisions in the proposed TOP Reliability Standards that require transmission operators to operate only within a subset of SOLs offsets the potential benefits the proposed Reliability Standards may otherwise provide.

43. The Commission believes that NERC's proposal for the treatment of SOLs affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11. Section 215(d)(4) requires that the Commission remand to the ERO for further consideration a Reliability Standard "that the Commission disapproves in whole or in part."[49] Thus, notwithstanding the organizational and administrative improvements contained in other provisions of proposed TOP Reliability Standards, our concern regarding the treatment of SOLs provides us no option other than to propose to remand the entire Reliability Standards TOP-001-2 and TOP-002-3.

44. In addition to addressing the SOL issue in the TOP Reliability Standards, we also propose to direct that NERC, on remand, develop modifications to the IRO Reliability Standards to ensure that reliability coordinators continue to develop and implement comprehensive generation and transmission outage coordination processes.

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[48] 2011 Southwest Outage Blackout Report at 1.

[49] 16 U.S.C. 824o(d)(4) (2012) (emphasis added).

45. Given that the SOL and outage coordination process issues pertain to numerous requirements across the proposed standards, the interrelationship among the TOP standards and between the TOP and IRO Reliability Standards, and that NERC requests that both sets of standards be addressed together, we propose to remand the entire set of TOP and IRO Reliability Standards.[50] This approach will give industry and NERC flexibility to develop modifications to the standards that address the concerns identified in this NOPR.

46. Further, the Commission discusses below certain provisions of NERC's proposal that require clarification or further technical explanation. Depending on the explanations provided by NERC and other interested entities in comments to this NOPR, additional Commission action may be appropriate, including the identification of additional issues that NERC must address on remand.

47. Finally, pursuant to section 215(d) of the FPA, we also propose to approve NERC's proposed revisions to Reliability Standard TOP-006-3. We find that proposed TOP-006-3 is sufficiently separate from the standards we propose to remand above. Below, we discuss: (A) the proposed TOP Standards; (B) the proposed IRO Standards; and (C) the proposed revisions to Reliability Standard TOP-006-3.

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[50] NERC TOP Petition at 1-2.

A. TOP Reliability Standards

1. Issue to be Addressed

a. Plan and Operate Within All SOLs

NERC Petition

48. Currently-effective Reliability Standard TOP-002-2a, Requirement R10 requires the transmission operator to plan to meet all SOLs and IROLs. Similarly, currently-effective Reliability Standard TOP-004-2, Requirement R1 requires transmission operators to operate within all IROLs and SOLs.

49. Proposed Reliability Standard TOP-002-3, Requirement R2 provides that each transmission operator still plan to operate within all IROLs but within only a sub-set of SOLs. It states that each transmission operator "shall develop a plan to operate within each [IROL] and each [SOL] which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator area" as a result of its Operational Planning Analysis performed in Reliability Standard TOP-002-3, Requirement R1.

50. NERC states that it is appropriate to limit Requirement R2 to a sub-set of "non-IROL SOLs" that are important to local areas and that the identified subset of non-IROL SOLs will be subject to the requirements of the proposed Reliability Standards. NERC states that non-IROL SOLs are typically thought of in terms of "equipment damage or

[element] loss of life" and are restricted to a limited or local area.[51] According to NERC, the standard drafting team concluded that it is not necessary to monitor all non-IROL SOLs because the "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue."[52] NERC explains that the "difference between non-IROL SOLs and IROLs is expressed in the difference between the consequences to the System (or impact to reliability) should unplanned perturbations of the system occur when the limit is being exceeded."[53] According to NERC, the consequences of exceeding an IROL are described as cascading, uncontrolled separation, or instability.[54] NERC states that the impact of exceeding a non-IROL SOL will not result in an Adverse Reliability Impact.[55]

<u>Commission Proposal</u>

51. The Commission is concerned with NERC's proposal because, unlike the currently-effective TOP Reliability Standards, the proposed standards do not require the

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[51] NERC states that the revised TOP requirements move the standards to where the NERC Operating Guidelines intended them to be and ensure that the reliability of the interconnected system will be maintained and even enhanced because system operators will not be distracted from true reliability issues by local system issues. NERC TOP Petition at 18.

[52] NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on Second Draft of Standards for Real-Time Operations) at 23.

[53] NERC TOP Petition at 19.

[54] *Id.*

[55] NERC TOP Petition at 19.

transmission operator to plan and operate within SOLs, only non-IROL SOLs that are identified by the transmission operator as supporting reliability internal to its area and identified as a result of an Operational Planning Analysis.[56] For example, non-IROL SOLs that appear to be excluded from the proposed standard are non-IROL SOLs that are in a transmission operator's area that impact another transmission operator's area or more than one transmission operator's area.

52. During deteriorating system conditions, an SOL can rapidly degrade into an IROL. Limiting the requirement for transmission operators to analyze and operate within SOLs only to non-IROL SOLs identified by the transmission operator for its internal area can reduce system reliability because operators have less situational awareness of the system and conditions. Even if we accept the argument that our rules for operating bulk electric facilities should not be concerned with "equipment damage or [element] loss of life," NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL

[56] NERC's Functional Model states one of the tasks of transmission operations is to "[d]evelop system limitations such as System Operating Limits…and operate within those limits." NERC's "Reliability Functional Model Function Definitions and Functional Entities Version 5" at 37 *available* at www.nerc.com.

SOLs exceedances until the system cascaded.[57] Thus, while non-IROL SOLs are essentially defined as not posing a risk of cascading outages, instability or uncontrolled separation if they are exceeded, experience indicates that operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability. The Commission believes that when any facility ratings or stability limits are exceeded or expected to be exceeded (i.e. causing a SOL or an expected SOL on jurisdictional facilities), these conditions should be mitigated to avoid the possibility of further deteriorating system conditions and a cascade event.

53. We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

54. Moreover, we believe that proposed Reliability Standard TOP-002-3, Requirement R1 is flawed because the transmission operator should have an operational plan to operate within all Bulk-Power System IROLs and SOLs for all cases when facility ratings or stability limits are exceeded during anticipated normal and contingency event conditions. The operational plan is needed to ensure the transmission operator operates

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[57] *See* 2003 Northeast Blackout Report at 74 and the 2011 Southwest Outage Blackout Report at 1.

in, or can return its system to, a reliable operating state. For example, the 2011 Southwest Outage Blackout Report raised a similar concern, stating that transmission operators should "ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency."[58] We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state. Absent such plans, system conditions can linger in an unsecure or emergency state exposing the system to cascading outages upon the next contingency. Thus, we are concerned that Requirement R1 is insufficient for the fundamental operation of the interconnected transmission network as proposed by NERC.

55. Similarly, proposed Reliability Standard TOP-001-2, Requirements R8 through R11 address transmission operator notification, operation and action with respect to IROLs and some SOLs based on the transmission operator's next-day Operational Planning Analysis. Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional

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[58] Southwest Outage Blackout Report (Recommendation 13 at 90). In addition, in Order No. 693 the Commission stated that operational plans for all IROLs should include the "[i]dentification and communication of control actions [to system operators] that can be implemented within 30 minutes" following a contingency to return the system to a reliable operating state...." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1601.

SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. Another example is if an unplanned outage of a transmission element or generator unit occurred after the completion of the next-day Operational Planning Analysis, this condition may result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now possibly exceeded due to the change in the system topology (i.e. transmission element outage) or generation dispatch (i.e. generator unit outage) that redirected the power flow on some portions of the interconnected transmission network.[59] Thus, there are various reasons why a SOL could occur in real-time operations due to the dynamic nature of the real-time interconnected transmission network and not be identified in the next-day Operational Planning Analysis. To assure that transmission operators are equipped to react to such

[59] This condition was identified in the 2011 Southwest Outage Blackout Report, which found that Imperial Irrigation District did not perform a separate, updated next-day study and contingency analysis for September 8, 2011 and instead, referenced a previous study which was not valid because it did not match the load and generation dispatch for the day. 2011 Southwest Outage Blackout Report, Recommendation No. 1 at 66.

situations, we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

56. Accordingly, pursuant to section 215(d)(4) of the FPA, we propose to remand proposed Reliability Standards TOP-001-2 and TOP-002-3. Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon. Our concerns discussed above apply to specific provisions of proposed TOP-001-2 and TOP-002-3. However, as explained above, we propose to remand proposed Reliability Standards TOP-001-2 and TOP-002-3. Moreover, as explained above, because the TOP standards are so interrelated, we also propose to remand Reliability Standard TOP-003-2 to give NERC and industry flexibility to address our concerns.

2. TOP Reliability Standards – Issues Requiring Clarification

a. System Models, Monitoring and Tools

NERC Petition

57. NERC proposes to retire TOP and IRO Reliability Standards that require reliability coordinators and transmission operators to maintain and use certain models and analysis capabilities and monitoring. NERC proposes to delete requirements for transmission operators to (1) "maintain accurate computer models utilized for analyzing and planning system operations"; (2) "use monitoring equipment to bring to the attention of operating personnel important deviations"; (3) "use sufficient metering … to ensure accurate and timely monitoring"; and (4) "have sufficient information and analysis tools to determine the cause(s) of SOL violations…."[60] NERC explains that these transmission operator requirements are unnecessary because transmission operators meet these requirements as part of NERC's certification process or are in other currently-effective or proposed standards.[61]

58. Similarly, NERC proposes to retire Reliability Standard IRO-002-2 Requirements R4, R5, R6, and R7, which address real-time monitoring and analysis capabilities and functions required to enable the reliability coordinator to perform its responsibilities. According to NERC, these requirements are unnecessary because they are inherent in the

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[60] *See* Reliability Standards TOP-002-2.1b, Requirement R19, TOP-006-2, Requirement R5, TOP-006-2, Requirement R6, and TOP-008-1, R4, respectively.

[61] NERC TOP Petition, Exhibit J at 22, 34, 35, and 38.

reliability coordinator's duty to maintain area control error or operate within IROLs/SOLs and can be verified in the certification process.[62] NERC also states that the Commission directives in Order No. 693 applicable to a minimum set of analytical tools and applicable to reliability coordinators and transmission operators will be addressed in Project 2009-02 - Real-time Monitoring and Analysis Capabilities – that has a projected completion date of 2014. Further, NERC proposes to retire other requirements of currently-effective Reliability Standard TOP-006-2 which address real-time monitoring responsibilities of the transmission operator.

Commission Proposal

59. In Order No. 693, the Commission directed NERC to develop requirements for a minimum set of analytical tools (analysis and monitoring capabilities) to ensure that a reliability coordinator has the tools it needs to perform its functions.[63] In its TOP Petition, NERC discusses the importance of analytical tools and real-time monitoring noting that, "[a]ccording to the August 2003 Blackout Report, a principal cause of the August 14, 2003 blackout was a lack of situational awareness, which was in turn the

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[62] Section 500 of NERC's Rules of Procedure provide for an organization certification program that is intended to ensure that the an applicant to be a reliability coordinator, balancing authority or transmission operator "has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational." NERC Rules of Procedure at 44.

[63] Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 905, 906, 1660.

result of inadequate reliability tools."[64] We agree with NERC's statement and believe this is an area of reliability that requires vigilance. Moreover, our view is reinforced by the 2011 Southwest Outage Blackout Report, which found that "[a]ffected TOP's real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems" and consequently recommended that "TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems."[65]

60. Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process,[66] we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. Monitoring and assessment capabilities must adapt to assess changing topography and system conditions so that

[64] NERC TOP Petition at 10. NERC also states that "the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14, contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations."

[65] 2011 Southwest Outage Blackout Report at 88 and Finding 12. In addition, the 2011 Southwest Outage Blackout Report , Finding 27 (at 111) states that "[a] TOP did not have tools in place to determine the phase angle difference between two terminals of its 500 kV line after it tripped."

[66] NERC TOP Petition, Exh. J at 33.

operators can continually maintain an adequate level of situational awareness. In contrast, certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

61. In addition, as discussed above, NERC indicates that Standards Project 2009-02, Real-time Monitoring and Analysis Capabilities, will address the Commission directives in Order No. 693 that address a minimum set of analytical tools. According to NERC, this project has a projected completion date of 2014. NERC's retiring of current IRO and TOP requirements that address monitoring and analysis capabilities warrants expedition in the completion of Project 2009-02. The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02.[67] Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

[67] NERC's "Standards Independent Experts Review Project" (Industry Experts Report) identifies one aspect of Project 2009-02 as a "high priority" gap. Industry Experts Report at Appendix F. The Industry Experts Report (App. F) identifies a high priority gap for Project 2009-02 to define the requirements for EMS RTCA models or performance expectations of the models; the Report also says proposed TOP-002 should incorporate current requirement for tools to determine cause of SOL violations.

b. <u>Compliance with Reliability Directives</u>

<u>NERC Petition</u>

62. Currently-effective Reliability Standard TOP-001-1, Requirements R3 and R4 require applicable entities to comply with transmission operators' and reliability coordinators' "reliability directives," which currently is an undefined term. NERC proposes Reliability Standard TOP-001-2, Requirement R1 which requires applicable entities to comply with transmission operators' "Reliability Directives," which NERC proposes to define as "[a] communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."[68]

63. In its implementation plan, NERC states that it is not proposing any new definitions but that the TOP standard drafting team coordinated with the IRO drafting team to develop a definition of "Reliability Directive." This definition is included in the IRO implementation plan.

<u>Commission Proposal</u>

64. The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. Also IRO Reliability Standards use the term "reliability directive" in the

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[68] NERC's proposed definition of Reliability Directive does not appear in the TOP Petition. Rather, NERC proposes the definition in the IRO Petition, Exhibit C at 1 (IRO Implementation Plan).

same manner as an undefined term.[69] In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network. NERC staff has noted in the context of how to communicate such directives that operating practices for such directives should be consistent, no matter what type of operating condition (normal, alert, emergency) exists.[70] Moreover, the transition from normal to emergency operation can be sudden and indistinguishable until recognized, often after the damage is done.[71]

65. NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding

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[69] *See* Reliability Standard IRO-002-2, Requirement R8.

[70] *See* COM-003-1, Operations Communications Protocols White Paper, May 2012 at 12, *available* at nerc.com.

[71] *See* NERC staff's letter to "Project 2009-22 Interpretation of COM-002-2 R2 for IRC Drafting Team" dated November 18, 2011, at 1, *available* at nerc.com.

the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

66. In addition, while NERC has included the proposed definition in its implementation plan, NERC has not explained or justified its request for approval of the revised definition. The Commission has held that definitions are standards.[72] Therefore, we cannot approve the definition without a technical justification.

c. <u>Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis</u>

<u>NERC Petition</u>

67. In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

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[72] As with Reliability Standards, the Commission reviews and approves revisions to the NERC glossary pursuant to FPA section 215(d)(2). Further, the Commission may direct a modification to address a specific matter identified by the Commission pursuant to section 215(d)(5). *See also* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1893-98.

Commission Proposal

68. It is unclear whether NERC's proposal would require transmission operators to include updated external networks to reflect operating conditions external to their systems and (internal and external) sub-100 kV facilities in their operational planning analyses. In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…."[73] The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.[74] Although proposed Reliability Standard TOP-002-3, Requirement R1 requires the transmission operator to consider "projected System conditions," it is unclear whether "projected System conditions" include the relevant updated external networks and (internal and external) sub-100 kV facilities.

69. The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating

[73] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1624.

[74] 2011 Southwest Outage Blackout Report, Recommendations Nos. 2 and 3.

conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

d. Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

NERC Petition

70. NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.[75] Proposed Requirement R7 requires each transmission operator to not operate outside any identified IROL "for a continuous duration exceeding its associated IROL T_v." Proposed Requirement R9 states each transmission operator shall not operate outside any SOL identified in Requirement R8 "for a continuous duration that could cause a violation of the Facility Rating or Stability criteria upon which it is based." Further, NERC proposes to replace Reliability

[75] NERC TOP Petition, Exhibit J at 25.

Standard TOP-008-1, Requirement R4 with multiple proposed requirements from proposed Reliability Standards TOP-001-2, TOP-002-3, and TOP-003-2. Reliability Standard TOP-008-1, Requirement R4 requires that the transmission operator have information and analysis tools to determine the causes of SOL violations, such as a most severe single contingency event, and conduct this analysis in all operating timeframes.

71. With regard to unknown operating states, currently-effective Reliability Standard TOP-004-2, Requirement R4 states that, if a transmission operator "enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes."[76] Order No. 693 directed NERC to modify Requirement R4 to restore the system "to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes."[77]

72. In the TOP Petition, NERC proposes to replace Requirement R4 with proposed Reliability Standard TOP-001-2, Requirements R7 through R11. Requirements R7 through 11 address the transmission operator's responsibilities over IROLs or SOLs that have been identified by the transmission operator as necessary to support reliability internal to its transmission operator area. NERC explains that the proposed requirements "do not include an explicit reference to 'unknown state' since system limits can and

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[76] Reliability Standard TOP-004-2, Requirement R4.

[77] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1636.

should be determined and conditions can be monitored to know when they have been exceeded."[78] NERC also states that unknown operating states "cannot exist because valid operating limits have been determined for all facilities in a TOP's footprint."[79] In addition, NERC states that the proposed requirements "prohibit operations outside of IROLs, or SOLs identified in TOP-001-2…."[80] Further, NERC explains that proposed Reliability Standard EOP-001-2, which applies to emergency operations planning, covers the general intent of being prepared to react to "Emergencies."[81]

Commission Proposal

73. NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency, to move quickly from an "unknown operating state" to within proven limits, and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed

[78] NERC TOP Petition, Exhibit H at 5.

[79] NERC TOP Petition, Exhibit I at 4.

[80] NERC TOP Petition, Exhibit H at 5.

[81] NERC TOP Petition, Exhibit I (Resolution of Order No. 693 directives) at 4.

replacement standards compare in meeting the same objectives as the current standards. We request comment on these concerns, as elaborated below.[82]

74. In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.[83] How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules? For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation? If so, is the difference significant for reliability purposes? Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability? Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the

[82] The 2011 Southwest Outage Blackout Report indicated that the September 8, 2011 cascade event "showed that the system was not being operated in a secure N-1 state" and that "[NERC's] mandatory Reliability Standards…require that the BES be operated so that it generally remains in a reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency." 2011 Southwest Outage Blackout Report at 5.

[83] Currently-effective Reliability Standard IRO-008-1, Requirement R2 requires that "[e]ach Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs."

proposed rules allow doing so while the current rules do not? Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially? Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

75. With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. In addition, a transmission operator could operate in an unanalyzed or unstudied state (as a result of loss of EMS facilities that meter and report voltage, MW flow and other key system indicators). For example, the 2011 Southwest Outage Blackout Report found that Western Area Power Administration-Lower Colorado was operating in an "unknown state" when it lost its real-time contingency analysis capabilities and, at the same time, did not notify its reliability coordinator to assist with situational awareness.[84] In light of

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[84] 2011 Southwest Outage Blackout Report, Recommendation 15, at 95 states that "[a]n entity should never be operating in an unknown state, as WALC [Western Area Power Administration-Lower Colorado] was when it lacked functional RTCA [real-time contingency analysis] and State Estimator, and did not ask any other entity to assist it with situational awareness." *Cf*. NERC Compliance Filing, Docket No. RM06-16-000 (Oct. 31, 2008) at 7 ("the Reliability Coordinators in the West operate only to study conditions and note that they do not operate in IROL conditions, only SOLs, unless there are one or more unanticipated outages. In these cases, when an IROL condition is

(continued…)

this concern, the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement. As above, our main question is whether the proposed rules are comparable to the current rules for reliability purposes and, if not, whether the difference is reasonable.

e. <u>System Protection Coordination</u>

<u>NERC Petition</u>

76. NERC proposes to replace currently-effective Requirements R2, R5 and R6 in Reliability Standard PRC-001-1, with proposed Reliability Standard TOP-003-2, Requirement R5.[85] Currently-effective Reliability Standard PRC-001-1, Requirement R2 requires generator operators and transmission operators to notify affected entities of relay or equipment failures and if the failure reduces system reliability, take corrective action as soon as possible. Requirement R5 requires generator operators and transmission operators to coordinate changes in generation, transmission, load or operating conditions with appropriate advance notice that could require changes in the protection systems of others. Requirement R6 obligates transmission operators and balancing authorities to

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experienced, the Reliability Coordinators must restore the system to a known operating state within 20 minutes for stability concerns and 30 minutes for thermal concerns.").

[85] NERC TOP Petition, Exhibit J at 40 and 41. According to NERC (petition at 4), the "corresponding changes in proposed PRC-001-2 are administrative in nature and are limited to removal of three requirements in currently-effective PRC-001-1 that are now addressed in proposed TOP-003-2, included herein for approval."

monitor the status of each special protection system in their area and to notify affected transmission operators and balancing authorities of a change in status.

77. Proposed Reliability Standard TOP-003-2, Requirement R5 states that entities "receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data." In the standard development process, the standard drafting team explained that a "data specification" is required to contain all of the information that a transmission operator and balancing authority needs to fulfill its obligations.[86] In addition, the standard drafting team stated that the transmission operator and balancing authority "are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading."[87] The standard drafting team indicated that "an auditor can only question what is contained in the requirements and in this case that

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[86] *E.g.,* NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on the 7th Draft) at 72. Southwest Power Pool Regional Entity stated that it "does not believe TOP-003-2 addresses the requirements in PRC-001." Exh. D at 73. Texas Reliability Entity states that "Requirements R2, R5 and R6 of PRC-001-1, which are proposed to be deleted, are not actually replaced by any new or revised requirements in other standards, resulting in reliability gaps." Exh. D at 89.

[87] NERC TOP Petition, Consideration of Comments (Consideration of Comments on the 7th Draft) at 79. Southwest Power Pool Standards Review Group states that "[t]o be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements." *Id.*

would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards."[88]

Commission Proposal

78. The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal.[89] Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.[90]

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[88] NERC TOP Petition, Consideration of Comments (Consideration of Comments on the 7th Draft) at 88. Southwest Power Pool Standards Review Group states that "incorporating protective relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification." *Id.* at 79.

[89] In Order No. 693, the Commission required changes to Requirement R2 of Reliability Standard PRC-001-1 to clarify "corrective action" (i.e., return a system to a stable state), specify time limit for notification, and require corrective action as soon as possible but no longer than 30 minutes. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1441, 1445 and 1449.

[90] In Order No. 693, the Commission directed NERC to develop a modification to Reliability Standard TOP-006-1 to clarify "the meaning of 'appropriate technical information' concerning protective relays" so that "operators can make better informed decisions. An example of such information would be the allowable reclosing angle set in the existing relays and the maximum angle at specific points in the Bulk-Power System that would be acceptable to allow closing of lines during system restoration." Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1663 and P 1665.

f. <u>Notification of Emergencies</u>

<u>NERC Petition</u>

79. Currently-effective TOP Reliability Standard TOP-001-1a requires each transmission operator to inform its reliability coordinator and other potentially affected transmission operators "of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency."[91] In its petition, NERC proposes to retire Reliability Standard TOP-001-1a and proposes as replacements Requirements R3-R6 of Reliability Standard TOP-001-2. In particular, Requirement R3 provides "[e]ach Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis."[92] In addition, Requirement R3 has a time horizon of "Operations Planning," which NERC describes as the "operating and resource plans from day-ahead up to and including seasonal" and does not include same-day operations or real-time operations.[93]

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[91] Reliability Standard TOP-001-1a, Requirement R5.

[92] The NERC Glossary defines Operational Planning Analysis as "[a]n analysis of the expected system conditions for the next day's operation... (That analysis may be performed either a day ahead or as much as 12 months ahead.). Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints."

[93] *See* NERC Time Horizons at 1, *available* at http://www.nerc.com/pa/Stand/Resources/Documents/TimeHorizons.pdf at 1.

Commission Proposal

80. NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.[94] Indeed, during the standard development process, similar concerns were expressed.[95]

81. Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. Proposed TOP-001-2, Requirement R5, states that "[e]ach [TOP] shall inform its [RC] and other [TOPs] of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas…." The definition of Adverse Reliability Impact in NERC's TOP filing is "[t]he impact of an event that results in frequency related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that

[94] An "anticipated" emergency should apply to all operational time horizons: operations planning, same-day, and real-time. Further, an "actual" emergency could only occur during the real-time operational time horizon.

[95] NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on the 7th Draft) at 21: "R3 seems to be missing some words…it is not clear if this requirement is supposed to be about planning ("expected to be affected by anticipated Emergencies") or real-time operations ("known to be affected by actual Emergencies") or both. If the latter is intended, the Time Horizon should include Real-Time Operations and Same Day Operations…." The standard drafting team responded that "it is clear as to what needs to be communicated." *Id.* at 23.

affects a widespread area of the Interconnection."[96] In contrast, NERC defines Emergency as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

82. While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion.[97] We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time

[96] NERC TOP Petition at 19. In the IRO Petition, NERC cites a different definition of Adverse Reliability Impact: "[t]he impact of an event that results in Bulk Electric System instability or cascading." NERC IRO Petition at 13, n20.

[97] NERC TOP Petition, Exhibit C at 3.

horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

83. In addition, as noted above, NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. NERC has not explained the intent or effect of the two definitions, and the term is used in several provisions of the proposed TOP and IRO Reliability Standards. The Commission seeks clarification and a technical explanation from NERC and other interested entities regarding the two definitions, including if it is proposing a revised definition, which definition it is proposing. In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

g. Primary Decision-Making Authority for Mitigation of IROLs/SOLs

84. NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

85. NERC states in its TOP Petition that "[t]he responsibility for monitoring and handling IROLs is primarily given to the Reliability Coordinator, but the Transmission Operator has the primary responsibility to designate any SOLs that require special

attention."[98] Likewise, NERC also states that an improvement resulting from the changes to the IRO Reliability Standards is that they delineate a clean division of responsibilities between the reliability coordinator and transmission operators to "help to ensure that the Reliability Coordinator is responsible for identifying and controlling operations associated with IROLs and the Transmission Operator is responsible for identifying and controlling operations associated with SOLs."[99] Proposed Reliability Standard IRO-001-3, Requirement R1, provides that each reliability coordinator "shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact." Further, currently-effective Reliability Standard IRO-009-1, Requirement R4 states that "[w]hen actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_v."[100]

86. However, proposed Reliability Standard TOP-001-2, Requirement R11 provides similar authority for the transmission operator with respect to IROLs. NERC proposes

[98] NERC TOP Petition at 15.

[99] NERC IRO Petition at 5-7.

[100] Reliability Standard IRO-009-1, Requirement R4.

that each transmission operator "shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8."[101]

87. NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act.[102] Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

B. IRO Reliability Standards

88. As discussed above, because of the interrelationship of the TOP and IRO Reliability Standards, the Commission proposes to remand proposed IRO Reliability Standards: IRO-001-3, IRO-002-3; IRO-005-4; and IRO-014-2. In addition, as discussed below, as part of the remand, the Commission proposes to direct that NERC develop modifications with regard to planned outage coordination. We also seek comment from NERC and other interested entities regarding several proposed provisions

[101] NERC's TOP Petition (at 15) states that "the delineation in the proposed TOP Reliability Standards with respect to operating within an identified IROL…is an important distinction in the proposed TOP Reliability Standards that is necessary for reliability."

[102] NERC in its 2009 filing to revise and add new IRO standards (RM10-15-000 petition at 8) states that under its "Functional Model, the reliability coordinator is the functional entity with the highest level of responsibility and authority for the real-time reliability of the bulk power system."

of the IRO Reliability Standards. Depending on the responses in the NOPR comments, the Commissions may issue further directives in the final rule in this proceeding.

1. Issues to be Addressed

a. Planned Outage Coordination

NERC Petition

89. In its IRO petition, NERC proposes to retire Reliability Standard IRO-005-3.1a, Requirement R6, which requires reliability coordinators to "coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes."[103] NERC states that the "coordination aspects of this part of Requirement R6 are addressed in the requirements of currently-effective IRO-008-1,[104] Requirement R3, and IRO-010-1a, Requirement R3," which provide:

> **IRO-008-1, R3.** When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
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> **IRO-010-1a, R3.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and

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[103] NERC IRO Petition at 33-34.

[104] NERC IRO Petition at 34.

information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

Commission Proposal

90. The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.[105]

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[105] The Independent Experts Report identifies outage coordination as one of the key areas where risk to the Bulk-Power System is not adequately mitigated. Industry Experts Report at 15. The Independent Experts Report proposes (Appendix H) to fill this gap "by giving the Reliability Coordinator the authority and responsibility to develop and implement a generation and transmission outage coordination process across Transmission Operators and Balancing Authorities in their footprint" and "between its adjacent Reliability Coordinators." Industry Experts Report at 31. This outage coordination process "shall cover the time period from the current operating hour out through at least 36 months." In addition, The 2011 Southwest Outage Blackout Report

(continued…)

91. Because outage coordination is critical to operations planning and the reliability coordinator has the needed wide-area view for operations planning, on remand, the Commission proposes to direct NERC to develop modifications to the IRO Reliability Standards that would require the reliability coordinator to have the authority and responsibility to develop and implement a generation and transmission outage coordination and planning process across transmission operators and balancing authorities in its footprint and between its adjacent reliability coordinators for the operations planning timeframe.[106]

2. IRO Reliability Standards – Issues Requiring Clarification

a. Use of a Secure Data Network

NERC Petition

92. Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC

(at 67) found a problem with Imperial Irrigation District's lack of awareness of another entity's planned generation outage.

[106] This proposed directive is consistent with the Order No. 693 directive for NERC to modify Reliability Standard TOP-003-1, Planned Outage Coordination, to require communication of scheduled outages to affected entities well in advance. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1620 through P 1624. In addition, the Commission has a similar concern with proposed Reliability Standard TOP-003-2 because it is not clear whether it addresses planned outage coordination.

Rules of Procedure, Section 1002 (Reliability Support Services).[107] NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3.

Commission Proposal

93. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

94. A secure network is essential to prevent unauthorized access to or modification of information that is critical for interconnected transmission network reliability functions performed by reliability coordinators. Therefore, we seek comment and technical explanation from NERC and other interested parties regarding how the identified section in the Rules of Procedure and Reliability Standard IRO-014-2, Requirements R1, R2, and

[107] NERC IRO Petition at 16, quoting section 1002 of the NERC Rules of Procedure which states in part that "NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC states that it will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service."

R3 ensure that the data exchange and notifications will be conducted using a secure mode in a secure environment.

b. Reliability Coordinator Monitoring of SOLs and IROLs

NERC Petition

95. NERC proposes to retire Reliability Standard IRO-002-2, Requirements R4 through R7, which require reliability coordinators to monitor IROLs and SOLs. Requirement R5 requires reliability coordinators to monitor bulk electric system elements that could result in SOL or IROL violations. NERC argues that it is appropriate to retire these requirements because: (1) an SOL is unlikely to have an impact on the wide-area reliability of the Bulk-Power System as it will generally not have an impact outside the affected transmission operator's area and (2) Requirement R4 is redundant with the requirements contained in existing Reliability Standards IRO-010-1a, and EOP-008-1.[108] NERC also asserts that these requirements are redundant with proposed Reliability Standard TOP-001-2, Requirements R8 through R11.

Commission Proposal

96. Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2

[108] NERC IRO Petition at 19-24.

Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

97. The reliability coordinator's monitoring function is important to ensure that the reliability coordinator can identify, assess and take appropriate action so that elements of the system do not operate outside established limits causing cascading outages or blackouts. Thus, monitoring is not simply a support function but a major reliability activity necessary to maintain situational awareness and ensure reliable operation of the interconnected transmission network. As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because an SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator.

98. Notwithstanding these concerns, currently-effective Reliability Standard IRO-003-2, Requirements R1 and R2 address the concern over monitoring of SOLs and IROLs, which provide:

> **R1**. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.
>
> **R2**. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or

> IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

Thus, the Commission seeks comment on whether the currently-effective Reliability Standard IRO-003-2 Requirements R1 and R2 require reliability coordinators to monitor all SOLs and IROLs.

C. Proposed Revisions to Reliability Standard TOP-006-3

99. Pursuant to section 215(d)(5) of the FPA, we propose to approve NERC's proposed revisions to Reliability Standard TOP-006-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We believe that the proposed revisions reasonably clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources is reasonable. Further, NERC's proposed revision to TOP-006-3 is consistent with the Commission's approval of NERC's approach to ensure that reliability entities have clear decision-making authority and capabilities to take appropriate actions with a clear division of responsibility with respect to balancing authority and transmission operator responsibilities during a system emergency.[109]

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[109] *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, 136 FERC ¶ 61,176 (2011).

III. Information Collection Statement

100. The Commission's information collection requirements are typically subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[110] However, by remanding the TOP and IRO Reliability Standards, any information collection requirements are unchanged. With regard to proposed Reliability Standard TOP-006-3, the Commission estimates that the information collection burden will not change as compared to the currently-effective standard. The reporting requirements for transmission operators and balancing authorities remain unchanged because the new requirements clarify the existing standard that the transmission operators report transmission information, while the balancing authorities report generation information.

IV. Environmental Analysis

101. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[111] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or

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[110] 44 U.S.C. 3507(d) (2012).

[111] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

procedural or that do not substantially change the effect of the regulations being amended.[112] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

102. The Regulatory Flexibility Act of 1980 (RFA)[113] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[114] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[115] The RFA is not implicated by this NOPR because the Commission is proposing to remand the TOP and IRO Reliability Standards and not proposing any modifications to the existing burden or reporting requirements. With no changes to the TOP and IRO Reliability Standards as

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[112] 18 CFR 380.4(a)(2)(ii).

[113] 5 U.S.C. 601-612.

[114] 13 CFR 121.201.

[115] *Id.* n.22.

approved, the Commission certifies that this NOPR will not have a significant economic impact on a substantial number of small entities.

103. In addition, for proposed Reliability Standard TOP-006-3, the Commission estimates that there will be no material change in burden for all small entities because the effect of the changes merely clarify that transmission operators are responsible for reporting transmission information while balancing authorities are responsible for reporting generation information.

VI. Comment Procedures

104. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER]**]. Comments must refer to Docket No. RM13-15-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

105. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

106. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

107. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

108. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

109. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

110. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Monitoring System Conditions - Transmission Operations Reliability Standard	Docket No. RM13-12-000
Transmission Operations Reliability Standards	Docket No. RM13-14-000
Interconnection Reliability Operations and Coordination Reliability Standards	Docket No. RM13-15-000

MOTION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TO DEFER ACTION

Pursuant to Rule 212 of the Federal Energy Regulatory Commission's ("FERC" or "the Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.212, the North American Electric Reliability Corporation ("NERC")[1] hereby submits this Motion to Defer Action on NERC's request to approve revisions to the Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards until **January 31, 2015**.

I. BACKGROUND

On April 5, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that Transmission Operators are responsible for monitoring and reporting available transmission resources and that Balancing Authorities are responsible for monitoring and reporting available generation resources.

On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection

[1] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR addressing the three petitions noted above (the TOP-006-3 petition, the TOP Standards petition, and the IRO Standards petition), which proposes to approve the proposed TOP-006-3 standard but remand the proposed TOP and IRO Standards.[2] In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."[3] For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.[4]

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[2] *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013)("NOPR").

[3] NOPR at P 4.

[4] NOPR at P 4.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[5]

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III. MOTION

Consistent with NERC's responsibility as the Electric Reliability Organization ("ERO") to develop Reliability Standards that provide for an adequate level of reliability of the Bulk-Power System, NERC respectfully requests that the Commission defer action in this proceeding to allow NERC time to consider the reliability concerns raised by the Commission in the NOPR. With respect to the proposed TOP and IRO Standards, NERC recently commissioned an independent review of its Reliability Standards, which also noted concerns with the TOP and IRO Reliability Standards submitted in this proceeding.[6] Specifically, the independent review identified the proposed TOP-001-2 (Transmission Operations), PRC-001-2 (System Protection

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[5] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

[6] *Available at*: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

Coordination), IRO-001-3 (Responsibilities and Authorities), and IRO-005-4 (Current Day Operations) as high risk standards requiring improvement.[7] Given these concerns, and the issues identified by the Commission in the NOPR, revisions to the proposed Reliability Standards may be required. Accordingly, NERC requests that the Commission defer action in this proceeding until **January 31, 2015**.[8]

NERC recognizes that proceeding through the administrative process of responding to the NOPR, especially given the concerns articulated by the Commission, will require a significant effort by NERC and industry. While this exercise is not without merit, a more efficient use of industry, NERC, and FERC's resources is to first examine the technical issues in the standards through NERC-led technical conferences with active industry and FERC participation. As described in **Attachment A**, NERC will hold two technical conferences to identify and assess concerns regarding the TOP and IRO Standards, such as the monitoring of SOLs, unknown operating states, and outage coordination. Concurrently, NERC will work with the NERC Standards Committee to re-formulate a standard drafting team to begin development work on revisions to the proposed standards, which would be informed by the technical conferences. Additionally, in response to the concerns noted by the Commission in the NOPR on the development of a minimum set of analytical tools (analysis and monitoring capabilities) to ensure that a Reliability Coordinator has the tools it needs to perform its functions ("Real-Time Tools"), NERC will continue development of standards that address Real-Time Tools as they relate to the proposed TOP and IRO standards, which could continue to be included as part of

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[7] The complete *Standards Independent Experts Review Project* report is available at: http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.

[8] With respect to the proposed TOP-006-3 Reliability Standard, while the Commission raised no significant concerns in the NOPR related to this standard, NERC requests that this Motion to Defer Action also apply to that pending standard given that it was addressed by the Commission in the same NOPR as the proposed TOP and IRO standards. NERC will re-file the proposed TOP-006-3 standard for approval separate from this proceeding.

Project 2009-02, Real-time Monitoring and Analysis Capabilities, or in revisions to the proposed TOP and IRO standards. Conforming changes to standards outside of the scope of this proceeding may be required depending on the extent of the changes made to the proposed TOP and IRO Standards.[9]

Deferring action on the NOPR until January 31, 2015 will provide NERC time to hold the technical conferences and develop any necessary revisions to the TOP and IRO standards for Commission approval. While a deferral until January 31, 2015 may seem extended at first glance, the proposed schedule is compressed given the complexity of these highly technical issues and the necessity to reach consensus through the standard development process. Given the scope of the work and the need for a deferral of Commission action on these standards, NERC commits to providing the Commission with quarterly reports regarding the status of revisions.

Accordingly, given the concerns articulated by the Commission in the NOPR, NERC respectfully requests an opportunity to work with industry and FERC to analyze the concerns and propose a new path forward. This Motion to Defer Action, if granted, would provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR, would afford time to review the proposed TOP and IRO Standards through the NERC standards development process, and would help the industry, NERC, and FERC work toward a common set of solutions to develop a set of standards that are technically justifiable and important for reliability.

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9 For example, in order to address the Commission's concerns with respect to the requirement in the proposed standards that a Transmission Operator must only provide notification of SOLs identified in a next-day Operational Planning Analysis rather than in the same-day or real-time operational time horizon, changes may need to be made to other IRO standards outside the scope of this proceeding.

IV. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission defer action in this proceeding until **January 31, 2015**.

Respectfully submitted,

/s/ Holly A. Hawkins

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Counsel for the North American Electric Reliability Corporation

December 20, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 20th day of December, 2013.

/s/ Holly A. Hawkins

Holly A. Hawkins

Counsel for North American Electric Reliability Corporation

ATTACHMENT A

Monitoring System Conditions – Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

DRAFT Technical Conference Agenda

I. The Need for Revisions to the TOP and IRO Reliability Standards

- Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013)
    - Proposed directives

II. Technical Issues

- System Operating Limits
    - Plan and Operate within all System Operating Limits
        - 30 Minute Timeframe or T_m concept

- System Models, Operating and Tools
    - Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating Status
    - Analysis capabilities in Real-time operations
    - Are requirements for monitoring necessary in standards or is certification a sufficient backstop for this capability?

- Primary Decision-Making Authority for Mitigation of Interconnection Reliability Operating Limits/System Operating Limits
    - Does the Reliability Coordinator have sole responsibility for IROLs?

- Planned Outage Coordination

- Use of the term 'Reliability Directive'

Standards Announcement Updated

Project 2014-03 Revisions to TOP and IRO Standards Standard Authorization Request

Formal Comment Period Now Open through March 24, 2014

Now Available

A 30-day formal comment period for the **Project 2014-03 – Revisions to TOP and IRO Standards** Standard Authorization Request (SAR) is open through **8 p.m. Eastern on Monday, March 24, 2014.**

Instructions for Commenting

The comment period is open through **8 p.m. Eastern on Monday, March 24, 2014.** Please use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards Standard Authorization Request

Informal Comment Period Now Open through March 24, 2014

Now Available

A 30-day informal comment period for the **Project 2014-03 – Revisions to TOP and IRO Standards** Standard Authorization Request (SAR) is open through **8 p.m. Eastern on Monday, March 24, 2014.**

Instructions for Commenting
The comment period is open through **8 p.m. Eastern on Monday, March 24, 2014.** Please use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

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Consideration of Comments

Project 2014-03 Revisions to TOP and IRO Standards

The Project 2014-03 Drafting Team thanks all commenters who submitted comments on SAR. These standards were posted for a 30-day public comment period from February 21, 2014 through March 24, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 24 sets of comments, including comments from approximately 103 different people from approximately 73 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

The SDT has made the following changes to the SAR as a result of industry comments:

- Modified the language to show that the intent of the SAR is simply to evaluate how best to respond to the directive in Order 693, paragraph 1855.
- Added the SW Outage Report as another source of input to the SDT deliberations.
- Added the Transmission Service Provider, Transmission Owner, and Interchange Authority to the list of applicable entities.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
No Additional Responses													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Member	Organization	Region	Segment
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities, Inc.	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Joseph DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

Jodi Jensen	Western Area Power Administration	MRO	1, 6
Joseph DePoorter	Madison Gas and Electric	MRO	3, 4, 5, 6
Ken Goldsmith	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
Marie Knox	Midcontinent Independent System Operator	MRO	
Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
Randi Nyholm	Minnesota Power	MRO	1, 5
Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Randi Heise	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
Louis Slade	Dominion	RFC	5, 6
Mike Garton	Dominion	NPCC	5, 6
Connie Lowe	Dominion	MRO	6
Michael Crowley	Dominion	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
Kent Kujala	NERC Compliance	RFC	3
Daniel Herring	NERC Training & Standards Development	RFC	4
Mark Stefaniak	Regulated Marketing	RFC	5
Barbara Holland	SOC	RFC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
Doug Hils		RFC	1
Lee Schuster		FRCC	3
Dale Goodwine		SERC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

Greg Cecil		FRCC	6

7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Service	FRCC	3
Stanley Rzad	Keys Energy Service	FRCC	1
Don Cuevas	Beaches Energy Services	FRCC	1
Mark Schultz	City of Green Cove Springs	FRCC	3

8.	Group	Bob Reynolds	SPP RE										X

No Additional Responses

9.	Group	Jason Marshall	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
2. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
3. Mohan Sachdeva	Buckeye Power	RFC	3, 4
4. Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
5. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
7. John Shaver	Southwest Transmission Cooperative	WECC	1
8. Bob Solomon	Hoosier Energy	RFC	1

10.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
Rich Ellison	Dispatch	WECC	1
Chris HIggins	Dispatch	WECC	1

11.	Group	Robert Rhodes	SPP Standards Review Group		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
Allan George	Sunflower Electric Power Corporation	SPP	1
Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
Mike Kidwell	Empire District Electric	SPP	1, 3, 5
Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
Valerie Pinamonti	American Electric Power	SPP	1, 3, 4, 5
Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
J. Scott Williams	City Utilities of Springfield	SPP	1, 4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
13.	Individual	Patti Metro	National Rural Electric Cooperative Association (NRECA)	X		X	X						
14.	Individual	Christina Conway	Oncor Electric Delivery Company LLC	X									
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
17.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
18.	Individual	Dave Willis	Idaho Power	X									
19.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
20.	Individual	Catherine Wesley	PJM Interconnection		X								
21.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
22.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
23.	Individual	Richard Vine	California ISO		X								
24.	Individual	Kenneth A Goldsmith	Alliant Energy				X						

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
N/A	N/A	N/A

1. Do you agree with the scope and contents of the SAR? If not, please provide specific comments and suggestions for SDT consideration.

Summary Consideration: The SAR is proposing to evaluate how to respond to the directive in Order 693, paragraph 1855. It is not a commitment to add requirements anywhere but simply to address the directive within this project. It is not a commitment to add requirements anywhere but simply to address the directive within this project. The directive links back to the TOP and IRO standards as it points to the fact that this issue isn't covered within those standards. If a change to standards is required, now that the IRO standards are opened up through this SAR and project, it may make sense to resolve the issue within the IRO standards as opposed to the VAR standards. If the issue can't be handled within this project, the directive will be returned to the VAR team. To clarify this, the language in the SAR has been modified.

Address the following directive from Order 693, paragraph 1855:

Organization	Yes or No	Question 1 Comment
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern Company proposes removing Item #5 from the SAR. First, Southern Company does not believe the scope of the SAR should include monitoring responsibilities for the Reliability Coordinator in the IRO family of standards. Southern Company agrees with NERC regarding the monitoring functions being an intrinsic part to the Reliability Coordinator's role. NERC proposed the retirement of Reliability Standard IRO-002-2 Requirements R4, R5, R6, and R7, which address real-time monitoring and analysis capabilities and functions required to enable the reliability coordinator to perform its responsibilities. NERC also believes these requirements are unnecessary because they are inherent in the reliability coordinator's duty to maintain area control error or operate within IROLs/SOLs and can be verified in the certification process. Likewise, Southern Company agrees with NERC and believes that there are requirements that require operation within SOLs and IROLs, which are more

Organization	Yes or No	Question 1 Comment
		“results based.” It is not practical to have a requirement to measure real-time monitoring nor is this necessary. The real reliability objective is to operate within identified parameters as required in IRO-005-3.1a, IRO-006_EAST-1, IRO-008-1, IROL-009-1, PER-005-1, TOP-001-2, TOP-002-2.1b, TOP-004-2, TOP-007-0, TOP-008-1, VAR-001-3, not to monitor. Secondly, as it relates to modifying the TOP and/or IRO standards to specifically assure that voltage and reactive resources are being maintained, there are multiple existing standards that require the Reliability Coordinator to establish and operate within SOL/IROLS, which include operating within system voltage limits. Modifying the TOP and/or IRO standards as shown in #5 of the SAR creates redundancy with existing standards, which goes against the Paragraph 81 principles. See the following standards that require the Reliability Coordinator to operate within SOLs and IROLs: o FAC-011-2: The purpose of FAC-011-2 states, “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” Since this requires documented methodology for SOLs, which includes system voltage limits, modifying the TOP and/or IRO standards as shown in #5 of the SAR would create redundancy with FAC-011-2. o FAC-014-2: The purpose of FAC-014-2 states, “To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” Since this standard requires establishment of SOLs and IROLs, which includes system voltage limits, modifying the TOP and/or IRO standards as shown in #5 of the SAR would create redundancy with FAC-014-2.

Organization	Yes or No	Question 1 Comment
		o IRO-008-1 R1: Modifying the TOP and/or IRO standards as shown in #5 of the SAR would create redundancy with IRO-008-1 R1 that requires RCs to perform assessments to ensure they do not exceed IROLs, which includes system voltage limits.
MRO NERC Standards Review Forum	No	This SAR is to respond to a NOPR concerning various TOP and IRO standards. The NSRF does not see how Item 5 in the "Detailed Description" should be included in the scope of this SAR. The FERC directive referenced discusses adding the Reliability Coordinator as an applicable entity in VAR-001 and does not tie it back to the TOP or IRO standards. Please remove item 5 from the detailed description
Alliant Energy	No	This SAR is to respond to a NOPR concerning various TOP and IRO standards. Alliant Energy does not see how Item 5 in the "Detailed Description" should be included in the scope of this SAR. The FERC directive referenced discusses adding the Reliability Coordinator as an applicable entity in VAR-001 and does not tie it back to the TOP or IRO standards. Please remove item 5 from the detailed description.
Response: The SAR is proposing to evaluate how to respond to the directive. It is not a commitment to add requirements anywhere but simply to address the directive within this project. The directive links back to the TOP and IRO standards as it points to the fact that this issue isn't covered within those standards. If a change to standards is required, now that the IRO standards are opened up through this SAR and project, it may make sense to resolve the issue within the IRO standards as opposed to the VAR standards. If the issue can't be handled within this project, the directive will be returned to the VAR team. To clarify this, the language in the SAR has been modified. Address the following directive from Order 693, paragraph 1855:		
Northeast Power Coordinating Council	No	TOP-001-2 Requirements R1 and R2 have wording issues that could result in double-jeopardy for non-compliance. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language allows for the potentially different reasoning being

Organization	Yes or No	Question 1 Comment
		allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be made into two requirements. Who's to say that the information is requested AND available? TOP-002 contains a potential conflict with FERC Order 888, requiring TOPs provide GOs with information about their role in SOL mitigation plans. The SAR must address these concerns.
Response: The comments will be passed to the SDT for consideration during development.		
Florida Municipal Power Agency	No	FMPA has only one comment on the SAR, and that is to not only address comments/input from the technical conference, but also the comments/input requested from industry related to the technical conference issues, and other issues raised by those commenters.
Response: The SDT will respond to all issues raised for this project regardless of whether they are explicitly noted or not. It is probably a fruitless exercise to try to list all possible sources but for additional clarity, the SDT has added the SW Outage Report as another source.		
American Transmission Company, LLC	No	When reviewing the proposed SAR, there is a series of IRO Reliability Standards listed in "Related Standards" section on pg.6 of the SAR, however, no reference to the TOP Standards. (see list below) o TOP-001-2-Transmission Operations o TOP-002-3-Operations Planning o TOP-003-2-Operational Reliability Data These TOP Standards are referenced in the FERC NOPR and also contained in the subject SAR Information (Industry Need).These TOPs are further described as part of the "Detailed Description" where the SDT Shall:1. Revise the TOP/IRO Reliability Standards filed under Projects 2007-03 and 2006-06 to address concerns expressed in the NOPR. ATC also noted that

Organization	Yes or No	Question 1 Comment
		the three TOPs listed above are included in the project tracking Spreadsheet found within the Weekly Standards Bulletin. Based on the above information, ATC recommends that the SDT consider adding the three TOPs listed above as “Related Standards” which are subject to revision as part of the scope for this Standards Project. a. Use the inputs from technical conferences to advise actions
Response: The three TOP standards referenced are part of the base project as shown in the details of the SAR and as such do not belong in the ‘Related Standards’ section of the SAR. That section shows standards that are not part of the base project and which might have to be revised in order to conform to changes made in the original subject TOP and IRO standards. No change made to the SAR. The SDT is obligated to use the inputs from the technical conferences.		
American Electric Power	No	AEP agrees with the overall approach taken by NERC to solicit industry input in addressing FERC’s concerns, however the current SAR lacks specificity, as it is not clear exactly how NERC proposes the identified standards be changed. AEP will reserve any agreement with the SAR until it is further developed.
Response: The SAR did not contain any proposed changes to the standards in question because the Technical Conferences were to provide input to the SDT as to what those changes should be. The SAR sets up the scope of work.		
Idaho Power	No	I do not believe that the SDT should address the goals in Project 2009-02. Address the FERC directives for the November 21, 2013 NOPR without increasing the scope of the project.
Response: The SAR provides discretion to the SDT in handling the goals of Project 2009-02 as needed but doesn’t mandate its inclusion in this project.		
Duke Energy	Yes	Duke Energy agrees with the scope of this project.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	Yes	We support the concept of deferring action on the standards to allow industry and NERC to address FERC concerns with the standards. Therefore, we are supportive of the SAR since its primary purpose is to address the concerns raised in the FERC NOPR. Since both of the original standards projects were initiated many years ago, much has changed with NERC's compliance and enforcement programs and standards processes. Reviewing the standards with these latest programs and processes in consideration makes sense at this juncture.
National Rural Electric Cooperative Association (NRECA)	Yes	NRECA filed in support the NERC filing to defer action on the subject TOP and IRO standards to allow industry and NERC to address FERC concerns with the standards. In doing so, NRECA agrees with the scope of the SAR since its primary purpose is to address the concerns raised in the FERC NOPR.
Oncor Electric Delivery Company LLC	Yes	Refer to Oncor's TOP/IRO Technical Conference comments for specific suggestions and recommendations for the SDT to consider.
PJM Interconnection	Yes	PJM supports the scope and approach of the SAR which will look to include other applicable standards, i.e., IRO standards, in response to FERC's remand of the TOP and IRO standards included in their NOPR issued November 21, 2013. PJM supported the revised TOP and IRO standards as submitted to the FERC in April, 2013 as they provided the correct authority and responsibilities for real time operations. To maintain the intent of those revised standards and to appropriately address the FERC's concerns in the NOPR, this SAR is employing a sound approach to review all applicable standards to assure situational awareness, maintain results-based standards and eliminate overlap in responsibilities and not delay response to real time operational issues that may have negative consequences.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	No comments
Dominion	Yes	
DTE Electric	Yes	
SPP RE	Yes	
Bonneville Power Administration	Yes	
SPP Standards Review Group	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
FirstEnergy	Yes	
Kansas City Power & Light	Yes	
California ISO	Yes	
Response: Thank you for your support.		

2. Are you aware of any regional variances associated with approved NERC Reliability Standards that will be needed as a result of this project? If yes, please identify the Regional Variance

Summary Consideration: No regional variances have been identified for relevance to this SAR.

Organization	Yes or No	Question 2 Comment
FirstEnergy	No	FE is not currently aware of any variance need, but the scope of the SAR should permit flexibility to add a variance within the development process to the extent required. The need for a variance may not arise until proposed requirements are reviewed by industry.
Response: The development process allows for the consideration of a variance at any time.		
Manitoba Hydro	No	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Northeast Power Coordinating Council	No	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	No	
Dominion	No	
DTE Electric	No	
Duke Energy	No	
Florida Municipal Power Agency	No	
SPP RE	No	
ACES Standards Collaborators	No	
Bonneville Power Administration	No	
SPP Standards Review Group	No	
Exelon	No	
National Rural Electric Cooperative Association (NRECA)	No	
Oncor Electric Delivery Company LLC	No	

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	No	
American Transmission Company, LLC	No	
American Electric Power	No	
Idaho Power	No	
PJM Interconnection	No	
Kansas City Power & Light	No	
California ISO	No	
Alliant Energy	No	
Response: Thank you for your response.		

3. **Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements**

Summary Consideration: No changes are required to the SAR due to concerns for Canadian provincial or regulatory requirements.

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	No	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Northeast Power Coordinating Council	No	
MRO NERC Standards Review Forum	No	
Dominion	No	
DTE Electric	No	

Organization	Yes or No	Question 3 Comment
Duke Energy	No	
Florida Municipal Power Agency	No	
SPP RE	No	
ACES Standards Collaborators	No	
Bonneville Power Administration	No	
SPP Standards Review Group	No	
Exelon	No	
National Rural Electric Cooperative Association (NRECA)	No	
Oncor Electric Delivery Company LLC	No	
Independent Electricity System Operator	No	
American Transmission Company, LLC	No	
American Electric Power	No	

Organization	Yes or No	Question 3 Comment
Idaho Power	No	
FirstEnergy	No	
PJM Interconnection	No	
Kansas City Power & Light	No	
Alliant Energy	No	
Response: Thank you for your response.		

4. Are there any other concerns with this SAR?

Summary Consideration: The SDT has added the Transmission Owner and Interchange Authority to the list of applicable entities due to industry comments pointing out that those two entities are applicable entities in proposed TOP-003.

Organization	Yes or No	Question 4 Comment
Dominion	Yes	Under the Reliability Functions; TO and IA are not selected. The TO and IA are applicable entities in TOP-003-2 and Dominion suggests selecting these entities.
Response: The SDT agrees and has made the indicated change.		
California ISO	Yes	When developing the specific standards associated with this SAR the drafting team should consider the following: 1. TOPs should operate to all SOLs, and not just a subset of SOLs. 2. The RC should have the primary responsibility for development of all IROLs. TOPs have an obligation and capability to develop SOLs. However, IROLs are a very specific subset of SOLs which require a wide area view to determine. In addition, there are IROLs that cross TOP boundaries which are therefore more suited to be identified by the RC. 3. SOLs should not all require complete mitigation within 30 minutes, as is required for more limiting IROLs. 4. The revised standards should address outage coordination as well. The RC should be required to create the overall outage coordination process and the TOP and BA should be required to follow the process.

Organization	Yes or No	Question 4 Comment
		5. The SDT should define "unknown operating state" within the revised standards. If this term cannot be adequately defined then it should not be used in the standard. 6. All TOPs should be required to know if they are not in a secure state (a state with acceptable N-1 performance). This will require that all TOPs have tools with the same (or similar) capability as RTCA.
Response: The comments will be passed to the SDT for consideration during development.		
ACES Standards Collaborators	No	We have no additional comments. Thank you for the opportunity to comment.
SPP Standards Review Group	No	We do not take issue with the SAR believing it provides very good coverage for the task at hand but we will be filing comments later on the Technical Conferences.
Oncor Electric Delivery Company LLC	No	Refer to Oncor's TOP/IRO Technical Conference comments for specific suggestions and recommendations for the SDT to consider.
Kansas City Power & Light	No	We do not take issue with the SAR believing it provides very good coverage for the task at hand but we will be filing comments later on the Technical Conferences.
Manitoba Hydro	No	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	

Organization	Yes or No	Question 4 Comment
Generation and Energy Marketing		
Northeast Power Coordinating Council	No	
MRO NERC Standards Review Forum	No	
DTE Electric	No	
Duke Energy	No	
Florida Municipal Power Agency	No	
SPP RE	No	
Bonneville Power Administration	No	
Exelon	No	
National Rural Electric Cooperative Association (NRECA)	No	
Independent Electricity System Operator	No	
Idaho Power	No	

Organization	Yes or No	Question 4 Comment
FirstEnergy	No	
Alliant Energy	No	
Response: Thank you for your support.		

END OF REPORT

TOP/IRO Technical Conference

Moderated by: Tom Bowe, PJM

March 6, 2014

Arlington, VA/Washington, DC

RELIABILITY | ACCOUNTABILITY




Agenda

- Introductory remarks
- Review of conference objectives, ground rules, and overview of next steps
- Discussion of technical issues raised in the FERC NOPR
    - Operating Concepts
    - Tools and Analysis
    - Coordination and Communication
- Recap of discussion and themes to carry forward to March 6 Technical Conference
- Concluding remarks

Antitrust Compliance Guidelines

- It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition. It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Public Announcement

- Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Introductory Remarks

Conference Objectives and Ground Rules

- Objectives
  - Discuss the technical issues raised in the FERC NOPR
  - Get everyone on the same page
  - Provide inputs to the DC Technical Conference that will provide the SDT with sufficient information and rationale to allow it to craft appropriate requirements that will resolve the concerns
- Ground Rules
  - Not the time to debate the FERC/NERC/industry model
  - Focus is on guidance that could assist SDT – so pose recommendations/solutions
  - Approximately twenty minutes per topic
    - Be concise
    - Leverage Parking Lot

Overview of Next Steps

- Draft SAR posted for comment February 21 through March 24
- Two one-day conferences to explore issues (March 3-4 and 6)
- Two weeks after conferences – Written comments due on issues
- April – SDT meets to consider inputs, revise SAR as needed, and create other supporting documents as required
- May – Post final SAR and draft standards with supporting documentation for 45 days
- August – second posting for 45 days
- October – final posting and ballot
- November 12, 2014 – Board adoption
- File by January 31, 2015

Overview

- April 16, 2013 – NERC petition for approval of three revised TOP, four revised IRO standards
- November 21, 2013 - FERC Notice of Proposed Rulemaking (NOPR) proposes to remand revised TOP and IRO standards
- December 20, 2013 – NERC motion to defer action on NOPR until January 31, 2015
- January 14, 2014 – FERC grants motion to defer action until January 15, 2015
- February 12, 2014 – Standards Committee appoints SDT for Project 2014-03 Revisions to TOP/IRO Reliability Standards

SDT Roster

- Chair – Dave Souder, PJM
- Vice Chair – Andrew Pankratz, FP&L
- David Bueche, CenterPoint Energy
- Jim Case, Entergy
- Allen Klassen, Westar Energy
- Bruce Larsen, WE Energies
- Jason Marshall, ACES Power Marketing
- Bert Peters, Arizona Public Service Co.
- Robert Rhodes, SPP
- Eric Senkowicz, FRCC
- Kevin Sherd, MISO

Discussion of Technical Issues

- Operating Concepts
- Tools and Analysis
- Coordination and Communication

Operating Concepts

- Decision making authority (paragraphs 84 & 87)
- Analysis of System Operating Limits (SOLs) (paragraphs 42 & 52)
- Mitigation Plans (paragraph 54)
- Operating to the Most Severe Single Contingency (paragraph 70)
- Unknown Operating States (paragraph 75)

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Decision Making Authority

- Submittal
- TOP-001-2, R11
- Each TOP shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

- NOPR (paragraph 87)
- NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the RC or the TOP has primary responsibility for IROLs

Analysis of System Operating Limits

- Submittal
- TOP-001-2, R8
- Each TOP shall inform its RC of each SOL which, while not an IROL, has been identified by the TOP as supporting reliability internal to its TOP Area based on its assessment of its Operational Planning Analysis

- NOPR (paragraph 42)
- Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the TOP internal to its area, system reliability is reduced and negative consequences can occur outside of the TOP's internal area

Mitigation Plans

- Submittal
- TOP-001-2, R7: Each TOP shall not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_v
- TOP-001-2, R8: Each TOP shall not operate outside any SOL identified in R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based

- NOPR (paragraph 54)
- The TOP should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state

Operating to the Most Severe Single Contingency

- Submittal
- Replaced by TOP-001-2, R7 & R9
- R7: Each TOP shall not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_v.
- R9: Each TOP shall not operate outside any SOL identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

- NOPR (paragraph 70)
- NERC proposes to delete TOP-004-2, Requirement R2, which provides that each TOP "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

Unknown Operating States

- Submittal
- Requirement deleted
- SDT viewed 'unknown operating states' as referring to lack of studies of all possible conditions. And, in today's environment, didn't feel that such a condition would exist.

- NOPR (paragraph 75)
- With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

Tools and Analysis

- Time Horizons (paragraph 55)
- System Models, Monitoring, and Tools (Transmission Operator - paragraph 60) (Reliability Coordinator – paragraph 95)
- Cause of SOL Violations (paragraph 73)
- Real-time Contingency Analysis (RTCA) (paragraph 74)
- External Networks and sub-100 kV Facilities and Contingencies (paragraph 67)

Time Horizons

- Submittal
- TOP-001-2, R8
- Each TOP shall inform its RC of each SOL which, while not an IROL, has been identified by the TOP as supporting reliability internal to its TOP Area based on its assessment of its Operational Planning Analysis. *[Time Horizon: Operations Planning]*

- NOPR (paragraph 55)
- Requirement R8 should pertain to all IROLs and all SOLs for all operating time horizons

System Models, Monitoring and Tools

- Submittal
- None – SDT believed certification covered this topic.

- NOPR (paragraph 60)
- Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. NERC indicates that these functions are assured through the certification process. We are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur.

Cause of SOL Violations

- Submittal
- Requirement deleted as Real-time is not when to investigate or to do root-cause analysis – but instead is the time to ‘fix’ the problem. Causes can be determined later and off-line.

- NOPR (paragraph 73)
- Proposal deletes requirement for determining the cause of SOL violations in all time-frames, including real-time

Real-time Contingency Analysis

- Submittal
- None – deferred to Project 2009-02

- NOPR (paragraph 74)
- Should all TOPs be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

External Networks and sub-100 kV Facilities and Contingencies

- Submittal
- TOP-002-3, R1
- Each TOP shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its TOP Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.

- NOPR (paragraph 67)
- Does 'projected System conditions' include external networks or sub-100 kV facilities?

Coordination and Communication

- Reliability Directive (paragraph 64)
- Corrective Action (paragraph 78)
- Notification of Emergencies (paragraph 80)
- Outage Coordination (paragraph 89)
- Secure Network (paragraph 92)

Reliability Directive

- Submittal
- Definition
- Reliability Directive — A communication initiated by an RC, TOP, or BA where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

- NOPR (paragraph 64)
- TOP now uses “reliability directive,” which does not appear to be limited to a specific set of circumstances. …, proposed definition of “Reliability Directive” appears to require compliance with directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a RC or TOP should be mandatory at all times, and not just during emergencies (unless safety is violated, etc.).

Corrective Action

- Submittal
- Requirement deleted
- The SDT believes that the proposed TOP-001-2 covers this situation for operations and that the proposed TOP-002-3 covers it for operations planning. The proposed standards do not limit the circumstances for which corrective actions need to be taken or what situation caused the problem. When exceedances occur, the TOP must take the prescribed actions.

- NOPR (paragraph 78)
- The Commission seeks comment and technical explanation on how current PRC-001-1 R2 requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal.

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Notification of Emergencies

- Submittal
- TOP-001-2, R3: Each TOP shall inform its RC and TOPs that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Time Horizon: Operations Planning]*
- TOP-001-2, R5: Each TOP shall inform its RC and other TOPs of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. *[Time Horizon: Same-day Operations, Real-Time Operations]*

- NOPR (paragraphs 80 – 82)
- We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed TOP-001-2 should apply to all emergencies, including real-time and same day emergencies.

Outage Coordination

- Submittal
- IRO-008-1, R3. When an RC determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the RC shall share its results with those entities that are expected to take those actions.
- IRO-010-1a, R3**.** Each BA, GO, GOP, IA, LSE, RC, TOP, and TO shall provide data and information, as specified, to the RC(s) with which it has a reliability relationship.

- NOPR (paragraph 89)
- The Commission does not see the specified requirements as dictating outage coordination.

Secure Network

- Submittal
- Requirement deleted

- NOPR (paragraph 92)
- Is there a need for a specific requirement that the data exchange between the RC, TOP, and BA be accomplished "via a secure network?"

Recap of Discussion and Themes to Carry Forward

- Items to be added as we go and then presented

Concluding Remarks

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TOP/IRO Technical Conference Notes

The notes contained in these slides are captured from participant discussions from technical conferences held on March 3-4, 2014 and March 6, 2014. The statements represent the views of various participants, and any conflicts or factual errors are a result of the “brainstorming” nature of the discussions.

RELIABILITY | ACCOUNTABILITY

Decision Making Authority

1. Should only be one responsible authority and that is the RC - plus RC has the wide-area view.
2. But TOP needs to protect its lines and RC can't push the 'button' - TOP & RC must work together – it is being done now, leverage existing practices.
3. Operating Plans are required and will cover majority of cases.
4. Need to differentiate between establishing IROL and enforcing it – right now IRO and TOP standards seem to conflict with both given authority to act, can't have possible conflicting actions.
5. Is there time for the RC to direct the TOP in all cases? Or are there times when the TOP must act quickly and coordinate later?
6. TOP-001-2, R10 says TOP must inform RC of actions so coordination is mandated.
7. Maybe a few words in standards needed to clarify responsibilities.
8. Need to explore 'version 0' standards to make sure that nothing got deleted that needs to be retained.

Analysis of System Operating Limits (SOLs)

1. How far outside of area does TOP look? One bus? SW Outage report said that was not sufficient (see recommendations 2 and 3).
2. Can't solve problems on other systems. But some SOLs overlap TOP areas. Need to plan & operate to all SOLs in own area. No hybrid set of SOLs.
3. TOP-003-2 takes care of data outside of area. TOP professional judgment of what it needs.
4. FAC standards mandate SOL methodology from RC but TOP should operate to all SOLs. FAC standards are not in scope of project.
5. But IROLs are different than SOLs and should be treated as such in standards. (see #9)
6. Need to review concerns in NOPR paragraphs 48 – 56 as well.
7. Need more clarity on SOLs – just thermal and stability? Need consistent understanding. SOLs are Facility Ratings and there are a lot of those. Can't exceed Facility Ratings.
8. Can we leverage how people are actually operating? Need to provide clear and simple guidelines to operator.
9. System performance should be the end result.

Mitigation Plans

1. SOLs have differing timeframes – not just 30 minutes for all. Facility ratings determine SOL timeframes as pointed out in FAC-008. SOLs in 30 minutes could cause actions that decrease reliability. 30 minutes simple for operators to work to. Don't want to get too complex. SW Outage Report talks about SOLs and the 30 minute timeframe.
2. T_v can never be more than 30 minutes. IROLs should thus be covered.
3. Special subset of SOLs is not desirable.
4. If the 4-hour rating allows 135% loading, when does an exceedance occur? If you exceed normal then do you go to emergency prior to action? Need to handle contingency after exceedance has occurred. Need to elaborate pre-contingency versus post-contingency actions.
5. White paper talks about T_m for SOLs which should be consistent with FAC-008. T_m tried in WECC but presented problems.
6. SOLs can't cause Cascading by definition. So, why is a timeframe needed for SOLs? Series of unmitigated SOLs caused problems in SW Outage. Can we use old Operating Manual for guidance on SOLs? Stay with fundamentals.
7. FRCC just says that when you reach 140%, consider as IROL. (maybe others as well)

Operating to the Most Severe Single Contingency (MSSC)

1. Doesn't operating to an IROL and T_v address this? And therefore MSSC specific language would be redundant?
   - The group in STL believed that this is the case. But DC may not agree (see #2).
2. Are there situations where you don't have a pre-determined IROL and you get pushed into an IROL?
   - If so, you need to move back to a secure state within 30 minutes or less. Is this an IROL or an unknown state?
   - If it isn't an IROL then do we need to retain old TOP-004-2, R2 to cover the situation? And should R2 only be a planning issue? Re-word to 'next n-1 should not exceed x%' instead of MSSC? Need a measurable requirement.
3. If you establish SOL & IROL correctly (as per FAC standards) then you will cover any single contingency, not just the MSSC.

Unknown Operating State

1. Unknown state is undefined and open to interpretation – 'unanalyzed and unstudied'. Always want to be operating in a 'known' state. Can you really always know what operating state you are in or will be in?
2. Seen as a loss of telemetry type situation? EOP-008-1, R1.6.2 talks of the need for plans on loss of functionality. Does this cover the issue? Should for functionality issues.
3. Today's technology should cover the limits issue. Loss of functionality is something different. Is a set of tools implied?
4. If 'unknown' remains, then it needs to be described as to what it means to an operator and clear actions spelled out. Operator needs full authority to act. Some entities have tried to define 'unknown' already – could leverage.

Time Horizons

1. Group agrees with NOPR comment in general. Need consistent approach to time horizons.
2. Would imply need for RTCA or similar. But not all TOPs can do RTCA.
3. What if something happens between next-day study and real-time? IRO-008-1, R2 talks of RC doing real-time assessment every 30 minutes – can this be adapted for TOP? Maybe. Is definition of real-time assessment lacking? Or upon topology change? Can we leverage 2009-02 white paper?
4. All SOLs issue covered previously.
5. RC doesn't really need all SOLs – it would actually distract them. Perhaps only exceedances. Would be more interested in plans to correct. If TOP needs others to act, does the RC need to get involved?

System Models, Monitoring, and Tools

1. Circuitous logic as certification is based on requirements. If requirements are removed then certification is weakened. This might work if there was a certification standard or re-certification effort.
2. Does new PER-005 cover any of this?
3. Should we just fall back to existing language in -0 standards? Then wait for 2009-02 to elaborate. We need to observe deadline and there are advances in these standards that should be implemented as quickly as possible. Might be points in 2009-02 white paper that could be used here.
4. Functional model dictates what a TOP needs to be able to do. But that doesn't set accountability.
5. Do we need to recognize size of TOP in solution? Impact of small entity could still be significant. Every Facility must be covered by someone somewhere – BES must be protected.
6. Do we need standards on tools? Some would like to see Project 2009-02 move forward. But doesn't believe timing fits for this project.

Cause of SOL Violations

1. Need to know cause to determine how to act – this is not root-cause but enough information to know how to mitigate in real-time. Tools could provide info to the extent operator needs it in real-time. Emphasis should be on fixing the problem.
2. Given other discussions (and subsequent requirements and fixes), this may be a redundant issue but need to provide rationale and mapping.

Real-time Contingency Analysis (RTCA)

1. Refer to Time Horizons issue for additional info
2. How to accommodate performance issues for any tools?
3. TOP should always know that they are n-1 secure in real-time – need to achieve acceptable system performance. How do they get this knowledge? Some sort of tool appears to be implied.
4. TOPs in WECC do not all have RTCA capability. Sometimes RC performs function for TOP who doesn’t have capability.
5. Functional model does talk about this and requires that TOP provide info to the RC on real-time situations
6. Size is issue again – every Facility needs to be covered somewhere by someone. Applicability a concern – all TOPs may not be correct.

External Networks and sub-100 kV Facilities and Contingencies

1. See *Analysis of SOLs slide* for additional info on this topic.
2. SDT may want to supplement existing language with explicit words concerning external and sub-100 kV data as needed to complete required tasks – may need to set bounds as per SW Outage report.

Reliability Directive

1. RC doesn't always know the exact conditions in a TOP area.
2. Definition of Emergency is broad and covers a lot of conditions – and no easy way to know when you have transitioned from normal to Emergency.
3. Need a way to comment on directions in 'normal' conditions but in 'emergencies' the party receiving the communication needs to act immediately. Need this tool as a 'club' to force action.
4. Need to provide clear guidance to operators on issue of directives – both as issuer and receiver. May need to identify as a Reliability Directive – no questions allowed, jump first and ask questions later. Also look at definition of Operating Instruction in COM-002-4.
5. Directives handled differently in different regions – need to study how it is done.
6. If everything is a directive then everything has same level of importance and that could be dangerous.
7. Need to check that RC, TOP, and BA both have clear and comparable requirements. Would need to make sure that DP is part of BA trail.

Corrective Action

1. Companies don't separate problems – whatever happens you need to correct it regardless of cause.
2. TOP-003 was designed to handle data on an all inclusive basis but having the data isn't the same as acting on it. Do we need to say that data recipients must utilize the data?
3. Could split out relay info as specific item in TOP-003 to provide additional weight to topic – is white paper guidance on what type of data needed required?
4. Original 693 directive (para. 1433) asked for clarification on time to correct.
5. Also concerns about R5 and R6 pertinence – are these the same as R2?

Notification of Emergencies

1. Do FAC-011 and FAC-014 cover this situation?
2. Same day operations may be problematic due to definition of Emergency – it is more real-time than anything else but some Emergencies may span multiple day timeframes.
3. What is the correct term: Emergency or Adverse Reliability Impact? Emergency may be the best term to use.
4. Shouldn’t TOP notify of any Emergency in any/all timeframe? That is, need to be sure to notify of Emergencies that emerge after OPA is completed but before real-time - but need to be careful of overloading operator. Can we prioritize?
5. Should TOP-001-2, R3 & R5 be combined?

Outage Coordination

1. Identified as a gap in the IERP report. Includes both generation and transmission.
2. Requirements inherently include coordination – can’t make a valid plan without coordination.
3. Approach should be the same for RC and TOP (and BA as needed).
4. Was existing language in TOP/IRO covering this explicitly? TOP-003-1.
5. Entities have different requirements now for coordination items.
6. Outage info is a vital concern that needs to be shown.
7. Is time line coordination an issue?
8. Outage coordination methodology requirement similar to FAC standards required? Or just general requirement(s) to have a documented plan with required participation? What does coordination really mean here?

Secure Network

1. IRO-002-2, R2 - only place in standards where term was used.
2. SDT said covered in ROP and IRO-014 and now redundant.
3. Everyone agrees that exchange should be secure and that current methods are secure.
4. How far does secure go? Once it leaves entity who is responsible?
5. Need to cover RC, TOP, and BA.
6. Need to continue concept somewhere in standards. Can existing language be retained?
7. If you adhere to COM and CIP is this covered? Need to check and perhaps provide better explanation as to why. Do we need 'security' experts to go off and draft response?
8. Could be covered in Project 2009-02 down the road.

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Unofficial Comment Form

Technical Conferences on Revisions to TOP and IRO Reliability Standards

Please use the electronic comment form to submit comments on the issues discussed during two Technical Conferences on Revisions to TOP and IRO Reliability Standards. These comments will be posted on the project webpage as part of the development record and considered by the drafting team for Project 2014-03 Revisions to TOP and IRO Reliability Standards as it develops revisions to the standards. Comments must be submitted by **8:00 p.m. Eastern on March 24, 2014.** If you have questions please contact Ed Dobrowolski (email) or by telephone at (609) 947-3673.

Background Information:
NERC recently held two technical conferences on revisions to standards pertaining to real-time operations and reliability coordination (the TOP and IRO Reliability standards). The first technical conference was held on March 3 and 4, 2014 in St. Louis and the second was held on March 6, 2014 in the Washington, DC area. The purpose of these conferences was to obtain industry input on issues identified in the Federal Energy Regulatory Commission's (FERC) notice of proposed rulemaking (NOPR) proposing to remand these standards.

In response to this NOPR, NERC filed a motion requesting that FERC defer action until January 31, 2015 to allow NERC and the industry time to consider the issues identified in the NOPR and develop revisions as needed to address them, and FERC granted the motion. Project 2014-03 was initiated to develop revisions to the TOP and IRO standards to address issues identified in the NOPR.

During the technical conferences, a presentation was used to facilitate a discussion of each of the issues identified in the NOPR. For each issue, a slide showing the language from the proposed standards along with a brief excerpt from the NOPR (along with the paragraph number) was prepared. Key points from the discussion in St. Louis were captured in a second presentation, and this presentation was provided to the participants in the second technical conference. During the second technical conference, additional key points were captured. The two presentations are posted on the project page.

During this informal comment period, NERC is requesting industry comments pertaining to the information provided in the conferences or suggestions for further consideration of issues identified in the NOPR. For purposes of discussion, these issues were grouped in three categories within the slides:

- Operating Concepts (including treatment of SOLs, operating to Most Severe Single Contingency, and unknown operating states)

- Tools and Analysis, including Real-time Contingency Analysis
- Coordination and Communication (including Reliability Directive, notification of Emergencies, and outage coordination)

Questions

You do not have to answer all questions. Enter all comments in plain text format. Bullets, numbers, and special formatting will not be retained.

1. In paragraphs 51 through 56 of the NOPR, the Commission expresses concerns with the treatment of System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) within the TOP standards. In particular, the Commission believes that the system should be planned and operated within all SOLs. Paragraph 73 and 74 of the NOPR asks for clarification as to whether the proposed treatment of IROLs and SOLs represents a different approach to real-time operational assessments and operation to the Most Severe Single Contingencies, and if so, what the technical justification is for the change. Paragraph 87 of the NOPR seeks clarification on who (the Transmission Operator or Reliability Coordinator) has primary responsibility for IROLs. Paragraphs 96, 97, and 98 discuss treatment of IROLs and SOLs within the proposed IRO standards and ask for clarification on monitoring of all SOLs and IROLs. Slides 12 through 15 in the Technical Conference presentation were used to discuss these issues, and slides 2 through 6 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments on the concerns identified by the Commission on the treatment of SOLs and IROLs, including planning and operating within all SOLs, planning to and operating to the Most Severe Single Contingency, and responsibility for monitoring of IROLs and SOLs, within the proposed standards.

   Comments:

2. In Paragraph 61 of the NOPR, the Commission asks for a schedule for completion of Project 2009-02 Real-time Monitoring and Analysis Capabilities. Paragraphs 74 and 75 of the NOPR identify possible concerns associated with lack of adequate situational awareness. The retirement in the proposed TOP and IRO standards of requirements to address monitoring and analysis capabilities may create a gap without the completion of Project 2009-02 or modifications to the proposed TOP and/or IRO standards. Please provide any comments or suggestions you have on the issue of system monitoring and analysis. Slides 19 and 21 in the Technical Conference presentation were used to discuss these issues, and slides 8 and 10 of the Notes presentation provides a recap of discussion from the two Technical Conferences.

   Comments:

3. Paragraphs 64 through 66 of the NOPR discuss the Commission's questions on the proposed defined term Reliability Directive. Since the proposed TOP and IRO standards and defined term were filed with FERC, the Project 2007-02 drafting team has proposed a new term, Operating

Instruction. Slide 24 in the Technical Conference presentation was used to discuss this issue, and slide 12 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments on the need for the term Reliability Directive and the questions on this term discussed in the NOPR.

Comments:

4. The currently enforceable TOP-004-2, Requirement R2 requires that a Transmission Operator that enters an unknown operating state …"restore operations to respect proven reliable power system limits within 30 minutes." The proposed TOP standards do not retain the undefined term "unknown operating state" because the parenthetical definition within TOP-004-2 indicates that an unknown operating state is "any state for which valid operating limits have not been determined" and other existing standards in the FAC family require that operating limits be established and communicated. In Paragraph 75 of the NOPR, the Commission identifies concerns with removal of the term "unknown operating state" from the proposed standards. Slide 16 in the Technical Conference presentation was used to discuss this issue, and slide 6 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments you have on the removal of the requirement to mitigate an "unknown operating state" by restoring operations to within proven reliability limits within 30 minutes.

   Comments:

5. Paragraph 78 of the NOPR concerns the proposed retirement of requirements from PRC-001-1 that address corrective actions. Slide 25 in the Technical Conference presentation was used to discuss this issue, and slide 13 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments you have on the proposed retirement of requirements from PRC-001-1.

   Comments:

6. Paragraphs 80 through 83 of the NOPR discuss concerns with notification of Emergencies, including the operational time horizon for such notifications. Slide 26 in the Technical Conference presentation was used to discuss this issue, and slide 14 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Do you agree that a Transmission Operator should inform its Reliability Coordinator of all Emergencies or anticipated Emergencies not only in the Operations Planning time horizon, as required by proposed TOP-001-2, Requirement R3, but also in the Same-day Operations and Real-time time horizons?

   Comments:

7. Paragraphs 68 and 90 of the NOPR identify concerns that the proposed standards no longer explicitly require coordination of outages. Slide 27 in the Technical Conference presentation was

used to discuss this issue, and slide 15 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments you have on the issue of outage coordination.

Comments:

8. Paragraphs 93 and 94 of the NOPR discuss concerns with removing language that requires data exchange to be conducted using a secure network. Slide 28 in the Technical Conference presentation was used to discuss this issue, and slide 16 in the Notes presentation provides a recap of discussion from the two Technical Conferences. Please provide any comments you have on this issue.

   Comments:

9. Please provide any additional comments you have for the drafting team on the issues identified in the NOPR.

   Comments:

145 FERC ¶ 61,158
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM13-12-000, RM13-14-000 and RM13-15-000]

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards

(Issued November 21, 2013)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to remand revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. In addition, the Commission proposes to approve NERC's proposed revisions to Reliability Standard TOP-006-3.

DATES: Comments are due **[Insert Date 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

145 FERC ¶ 61,158
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Monitoring System Conditions - Transmission Operations Reliability Standard	Docket No. RM13-12-000
Transmission Operations Reliability Standards	Docket No. RM13-14-000
Interconnection Reliability Operations and Coordination Reliability Standards	Docket No. RM13-15-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 21, 2013)

1. Pursuant to section 215(d) of the Federal Power Act (FPA),[1] the Commission proposes to remand revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards. In addition, the Commission proposes to approve NERC's proposed revision to Reliability Standard TOP-006-3 concerning the monitoring role and notification obligation of reliability coordinators, balancing authorities and transmission operators. The Commission seeks comments on its proposals.

[1] 16 U.S.C. 824o(d) (2012).

2. NERC filed changes to the TOP Reliability Standards (Docket No. RM13-14-000) concurrently with its proposal to modify the IRO Reliability Standards (Docket No. RM13-15-000). NERC requests that the Commission process the two proposals together. In addition, NERC separately filed revisions to Reliability Standard TOP-006-3 (Docket No. RM13-12-000) that NERC proposes to become effective prior to the effective date of the revisions to the TOP Reliability Standards in Docket No. RM13-14-000. Because the proposed TOP and IRO Reliability Standards are interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involve similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the Commission addresses the three proposals together in this Notice of Proposed Rulemaking (NOPR).

3. NERC explains that the set of TOP Reliability Standards "address the important reliability goal of ensuring that the transmission system is operating within operating limits."[2] The TOP Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities of transmission operators. The set of IRO Standards apply to the responsibility and authority of reliability coordinators, the entities with the highest level of authority that are responsible for reliable operation of the bulk electric system, and have the wide-area view of the bulk

[2] NERC TOP Petition at 3.

electric system. The IRO Standards, which complement the TOP Standards, have the goal of ensuring that the bulk electric system is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.[3] Thus, together, the TOP and IRO Reliability Standards address matters that are fundamental to grid reliability as they pertain to the coordinated efforts to operate the bulk electric system in a reliable manner during real-time operations.

4. Based on our review of the NERC petitions, it appears that the proposed TOP and IRO Reliability Standards contain some improvements over the current standards. Specifically, the revised standards include organizational and administrative improvements that reduce redundancy and clarify the delineation between applicable entities with regard to certain tasks. The Commission appreciates efforts to clarify standards and reduce redundancies.[4] However, we are concerned that the changes in the proposed standards create reliability gaps in the standards that are critical to reliable operation of the Bulk-Power System. While NERC indicates that the revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements, we are concerned that NERC has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these

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[3] *See* NERC IRO Petition at 6.

[4] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

aspects in the proposed standards. One area of concern is that, unlike the currently-effective TOP Reliability Standards, there is no requirement in the proposed standards for transmission operators to plan and operate within all System Operating Limits (SOLs).[5] The provisions in the proposed TOP Reliability Standards that require transmission operators to operate only within a subset of SOLs offset the potential improvements. The Commission believes that NERC's proposal for the treatment of SOLs adversely impacts multiple requirements in the proposed TOP Reliability Standards. Moreover, as discussed herein, the Commission identifies other concerns that may need to be addressed in order not to create further reliability gaps. Section 215(d)(4) requires that the Commission remand to the ERO for further consideration a Reliability Standard "that the Commission disapproves in whole *or in part*."[6] Thus, notwithstanding the improvements mentioned above, the concern regarding the treatment of SOLs, and potentially other concerns discussed below, leads us to propose to remand the proposed TOP standards. In addition, given the interrelationship between the TOP and IRO Reliability Standards

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[5] NERC defines a SOL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits [pre- and post-Contingency] are based upon certain operating criteria. … "

[6] 16 U.S.C. 824o(d)(4) (2012) (emphasis added).

and that NERC requests that both sets of standards be addressed together,[7] we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.

5. In addition to the concerns regarding the treatment of SOLs, the Commission has identified a reliability gap in the IRO Reliability Standards and accordingly proposes to direct that NERC develop modifications in these standards to ensure that reliability coordinators continue to develop and implement comprehensive generation and transmission outage coordination processes.

6. Further, we discuss below additional issues regarding the proposed TOP and IRO Reliability Standards that require clarification or further explanation and technical justification. Depending on the explanations provided by NERC and other interested entities in their comments to this NOPR, additional Commission action may be appropriate, including directives that NERC must address in response to a final rule in this proceeding.

[7] NERC TOP Petition at 2 (stating that "simultaneous approval of both petitions by the Commission will help ensure a smooth transition and implementation of the proposed Reliability Standards for both the industry and the ERO.").

I. **Background**

7. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 initial Reliability Standards filed by NERC, including the existing TOP and IRO Reliability Standards.[8] In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards; however, none of the standards approved in Order No. 748 are at issue in this NOPR.[9]

A. **NERC's TOP Petition (Docket No. RM13-14-000)**

8. On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards.

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[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

NERC also seeks approval of the implementation plan for the proposed TOP Reliability Standards and approval of the retirement of eight TOP and one PER Reliability Standards,[10] and to retire Requirements R2, R5, and R6 of Reliability Standard PRC-001-1.

9. NERC states that the proposed TOP Reliability Standards represent significant revision and improvement to the current set of enforceable Reliability Standards by upgrading the overall quality of the standards, eliminating gaps in the requirements, ambiguity, redundancies, and addressing Order No. 693 directives. NERC adds that the proposed TOP Reliability Standards are also more efficient than the currently-effective standards because they incorporate the necessary requirements from today's standards into three cohesive, comprehensive Reliability Standards "that are focused on achieving a specific result."[11] NERC states that the proposed TOP Reliability Standards, along with the proposed IRO Reliability Standards, will help to ensure better coordination for

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[10] TOP-001-1a – (Reliability Responsibilities and Authorities); TOP-002-2.1b (Normal Operations Planning); TOP-003-1 (Planned Outage Coordination); TOP-004-2 (Transmission Operations); TOP-005-2a (Operational Reliability Information); TOP-006-2 (Monitoring System Conditions); TOP-007-0 (Reporting System Operating Limit and Interconnection Reliability Operating Limit Violations); TOP-008-1(Response to Transmission Limit Violations); and on Personnel Performance, Training, and Qualifications (PER) Reliability Standard, PER-001-0.2 (Operating Personnel Responsibility and Authority).

[11] NERC TOP Petition at 4, 11, 42. NERC explains that the corresponding changes in proposed Reliability Standard PRC-001-2 are administrative in nature and are limited to removal of three requirements in currently-effective Reliability Standard PRC-001-1 that are now addressed in proposed Reliability Standard TOP-003-2.

transmission operators and reliability coordinators to "plan and operate the interconnected Bulk Electric System in a synchronized manner to perform reliably under normal and abnormal conditions."[12]

10. NERC states that the proposed TOP Reliability Standards are a significant improvement from the currently-effective TOP Reliability Standards in three ways. First, NERC explains that the proposed TOP Reliability Standards "rais[e] the bar on system performance by mandating that all IROLs be resolved within the IROL T_v, which is a significant increase in performance over the existing Reliability Standards."[13] NERC indicates that the proposed TOP Reliability Standards adopt an approach "for operating within a subset of SOLs that more closely aligns with the original NERC Operating Guidelines."[14] Second, NERC states that it improved the proposed Reliability Standards by designating requirements to apply solely to transmission operators and removing several of the requirements applicable to reliability coordinators. NERC explains that it

[12] NERC TOP Petition at 9.

[13] NERC TOP Petition at 11. The Interconnection Reliability Operating Limit (IROL) T_v is defined in the NERC Glossary of Terms as: "The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes."

[14] NERC TOP Petition at 11. NERC states that "[p]rior to becoming the ERO, NERC guidelines for power system operation and accreditation were referred to as the NERC Operating Guidelines, for which compliance was strongly encouraged yet ultimately voluntary." *Id.* at n.23.

added requirements applicable to reliability coordinators to the proposed IRO Reliability Standards. Third, NERC states it consolidated "the necessary requirements from the eight existing TOP Reliability Standards into three cohesive, comprehensive Reliability Standards."[15] The specific revisions to the TOP Reliability Standards are as follows:

<u>TOP-001-2 (Transmission Operations)[16]</u>

11. In the TOP petition, NERC explains that the requirements of proposed Reliability Standard TOP-001-2 address the following matters: (1) transmission operator "Reliability Directives" (proposed Requirements R1 and R2); (2) emergencies and emergency assistance (proposed Requirements R3-R6); and (3) IROLs and SOLs (proposed Requirements R7-R11). Proposed Requirements R1 and R2 state:

> **R1.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.
>
> **R2.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

NERC states that proposed Requirement R1 recognizes the reliability need to give transmission operators the ability to issue Reliability Directives to various entities,

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[15] NERC TOP Petition at 11.

[16] The proposed TOP and IRO Reliability Standards are not attached to the NOPR. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket Nos. RM13-14 and RM13-15 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

subject to limited exceptions in cases where such actions would violate safety, equipment, regulatory, or statutory requirements. NERC explains that Requirement R2 requires entities receiving the directive from the transmission operator to inform the transmission operator in situations where an identified Reliability Directive cannot be performed. NERC explains that these requirements give transmission operators the authority to issue Reliability Directives when needed, but also provide them the flexibility to take different action in those situations where an entity notifies its transmission operator of its inability to comply with a Reliability Directive.[17]

12. With regard to emergencies and emergency assistance, NERC proposes Requirements R3 through R6:

> **R3.** Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.
>
> **R4.** Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.

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[17] NERC TOP Petition at 12-13.

> **R6.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

NERC states that proposed Requirements R3, R5, and R6 apply to the coordination aspects of interconnected operation. NERC explains that proposed Requirement R3 requires a transmission operator to inform its reliability coordinators and other transmission operators of actual and anticipated emergencies based on its assessment of its "Operational Planning Analysis."[18] NERC states that, in situations "where emergency assistance is needed, proposed Requirement R4 requires that Transmission Operators render emergency assistance to other Transmission Operators when it is requested and available" and that proposed Requirement R5 "requires Transmission Operators to inform entities (Reliability Coordinators and other Transmission Operators) of operations that may adversely impact them."[19] According to NERC, this proposed requirement addresses the Order No. 693 directive to consider the need for the transmission operator to notify the reliability coordinator or the balancing authority when facilities are removed

[18] NERC defines an Operational Planning Analysis as "[a]n analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." NERC Glossary of Terms at 47.

[19] NERC TOP Petition at 14.

from service.[20] NERC states that proposed Requirement R6 requires balancing authorities and transmission operators to notify the reliability coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment.

13. With respect to treatment of SOLs and IROLs, NERC explains that the standard drafting team examined the requirements for SOLs and IROLs in the currently-effective TOP Reliability Standards to ensure whether they adequately addressed the handling of these limits. In particular, the standard drafting team was concerned that the transition from the NERC Operating Guidelines to the Version 0 standards had resulted in an incorrect emphasis on non-IROL SOLs as opposed to IROLs. The standard drafting team noted a discrepancy among the three currently-effective SOL/IROL-related requirements.[21] According to NERC, in Reliability Standards TOP-002-2a, Requirement R10 and TOP-004-2, Requirement R1, applicable entities are expected to plan and operate to meet all SOLs and IROLs, while in TOP-007-0, R1, entities are only instructed

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[20] NERC TOP Petition at 14 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1588).

[21] TOP-002-2a, Requirement R10: Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). TOP-004-2, Requirement R1: Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). TOP-007-0, Requirement R2: Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

to take action for IROLs. According to NERC, the standard drafting team concluded that the Version 0 standards did not accurately reflect what the operating policies stated. Nevertheless, the standard drafting team determined that non-IROL SOLs are still important. NERC explains that reliability risk to the system exists when the system is operating in conditions such that an IROL limit is exceeded for a time exceeding T_v. Consequently, NERC revised the requirements related to operating within limits by tying IROL actions to T_v. NERC proposes Requirements R7 through R11 to address the transmission operator's responsibilities over IROLs[22] or SOLs[23] that the transmission operator identifies as necessary to support reliability internal to its transmission operator area:

> **R7.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
>
> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**

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[22] NERC defines an IROL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."

[23] NERC defines a SOL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits [pre- and post-Contingency] are based upon certain operating criteria. … "

> **R9.** Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R10.** Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
>
> **R11.** Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

NERC explains that the responsibility for monitoring and handling IROLs is primarily given to the reliability coordinator, but the transmission operator has the primary responsibility to designate any SOLs that require special attention. NERC indicates that the delineation in the proposed TOP Reliability Standards with respect to operating within an identified IROL and in designating important SOLs is an important distinction in the proposed TOP Reliability Standards that is necessary for reliability.

14. NERC adds that the proposed TOP Reliability Standards include a requirement that provides for "the identification of a sub-set of non-IROL SOLs that are identified as important for local areas."[24] NERC indicates that the proposed requirements mandate exceedances of these non-IROL SOLs to be monitored and reported to the reliability coordinator, giving transmission operators "the ability to ensure that any non-IROL SOLs

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[24] NERC TOP Petition at 19.

that are of concern to the transmission operator will be monitored to ensure local consequences are managed."[25]

15. NERC states that the "difference between non-IROL SOLs and IROLs is expressed in the difference between the consequences to the System (or impact to reliability) should unplanned perturbations of the System occur when the limit is being exceeded. For an IROL, the consequences are described as Cascading, uncontrolled separation, or instability."[26] NERC explains that the consequences of non-IROL SOLs are typically thought of in terms of equipment damage or total loss of an element and are restricted to a limited or local area. NERC states that the revised TOP requirements move the standards to where the NERC Operating Guidelines intended them to be and ensure that the reliability of the interconnected system will be maintained and even enhanced because system operators "will not be distracted from true reliability issues by local system issues."[27] NERC states that the impact of exceeding a non-IROL SOL will not result in an Adverse Reliability Impact.[28]

16. According to NERC, transmission operators may also identify and communicate to their reliability coordinator any of the non-IROL SOLs that are believed or anticipated

[25] *Id.* at 19-20.

[26] *Id.* at 19.

[27] NERC TOP Petition at 18.

[28] NERC TOP Petition at 18-19.

to have potential to develop into IROLs and, thus, to ensure that they too are monitored and managed. NERC also explains that, while non-IROL SOLs are similar to IROLs in that non-IROL SOLs must respect the ratings of equipment associated with the facilities to which the non-IROL SOL applies, there is no specific requirement established for a time exceedance similar to the T_v of an IROL. According to NERC, because T_v may be less than 30 minutes, T_v "mandates a tighter time frame for action than the 30-minute time that is mandated in the currently-effective standards, thereby improving reliability of the bulk power system."[29]

Proposed TOP-002-3 (Operations Planning)

17. NERC states that proposed Reliability Standard TOP-002-3 Requirements R1 through R3 require transmission operators to perform Operational Planning Analyses to ensure operations within IROLs and SOLs. The requirements for proposed Reliability Standard TOP-002-3 are as follows:

> **R1.** Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
>
> **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

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[29] NERC TOP Petition at 18.

> **R3.** Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC explains that Requirement R1 requires transmission operators to have an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed any of its facility ratings or stability limits during anticipated normal and contingency event conditions. NERC also explains that Requirement R2 requires transmission operators to develop a plan that will help ensure they do not operate in excess of limits identified in the Operational Planning Analysis. NERC indicates that Requirement R3 requires that entities be notified if they are identified in the transmission operator's plans and that the notification should inform entities of their role in the plans.

18. According to NERC, requiring transmission operators to perform Operational Planning Analyses that incorporate normal and contingency situations for next-day operations while assuring appropriate limits are not violated assures that the transmission operators "will have a plan to follow during Real-time operations that accurately reflects the anticipated conditions of the day's operations, including the ability to deliver generation to Load."[30] NERC adds that Requirement R3 is similar to the coordination requirements established in proposed Reliability Standard TOP-001-2 by ensuring that all entities know their role in next-day operations.

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[30] NERC TOP Petition at 22.

Proposed TOP-003-2 (Operational Reliability Data)

19. NERC states that proposed Reliability Standard TOP-003-2, Requirements R1 through R5 were adapted for transmission operators and balancing authorities based on similar, Commission-approved requirements for reliability coordinators.[31] The proposed requirements include:

> **R1.** Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include:
> - **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.
> - **1.2.** A mutually-agreeable format.
> - **1.3.** A periodicity for providing data.
> - **1.4.** The deadline by which the respondent is to provide the indicated data.
>
> **R2.** Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring…
>
> **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification…shall satisfy the obligations of the documented specifications for data.

NERC states that the proposed requirements emphasize the need for transmission operators and balancing authorities to obtain all of the data they need for reliability purposes and mandate that entities that have this data timely provide it to the transmission operator and balancing authority. According to NERC, lack of adequate data for real-time operations and modeling have contributed to system incidents in the past, and the

[31] NERC TOP Petition at 23 (citing Reliability Standard IRO-010-1a.)

data specification concept will eliminate this problem by allowing transmission operators and balancing authorities to require entities to send them any required data.

NERC's Response to Order No. 693 Directives and Analysis of Southwest Outage Report

20. NERC indicates that its staff analyzed the recommendations from the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations ("2011 Southwest Outage Blackout Report") that apply to transmission operators and compared the recommendations to both the currently-effective TOP Reliability Standards and the proposed Reliability Standards.[32] The TOP Petition provides that, "[b]ased on this analysis, NERC staff believes that if entities complied with the proposed TOP Reliability Standards, the likelihood of such an event occurring would be significantly diminished."[33] NERC includes as Exhibit H a detailed report on this analysis, including the relevant 2011 Southwest Outage Blackout Report recommendations with an explanation of how the relevant recommendations would be addressed in the proposed TOP Reliability Standards.

21. The NERC TOP Petition includes a summary of nine Order No. 693 directives related to the proposed TOP Reliability Standards and NERC's responses to those directives in Exhibit I. NERC also explains that, rather than addressing two directives from Order No. 693 relating to minimum analysis and monitoring capabilities in the

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[32] NERC TOP Petition at 6 and Exh. H.

[33] NERC TOP Petition at 6.

proposed TOP Reliability Standards and proposed IRO Reliability Standards, the standard drafting team chose to have them addressed by the Project 2009-02 Standard Drafting Team.[34] According to NERC, it "is developing a set of Reliability Standards in Project 2009-02, which is expected to be completed in 2014," that will establish requirements for the functionality, performance, and maintenance of real-time monitoring and analysis capabilities for reliability coordinators, transmission operators, generator operators, and balancing authorities for use by their system operators in support of reliable system operations.[35]

<u>TOP Implementation Plan</u>

22. NERC states that some of the proposed revisions to the TOP Reliability Standards are dependent on corresponding changes to proposed IRO Reliability Standards (IRO-001-3 and IRO-005-4) and to one Verification and Data Reporting of Generator Real and Reactive Power Capability Reliability Standard - MOD-025-2. NERC states that the proposed TOP Reliability Standards cannot be implemented until all three of the above standards have been implemented.

23. In its implementation plan, NERC also states that there "are no new definitions in the proposed set of standards" but the standard drafting teams for the TOP and IRO

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[34] One directive is applicable to Reliability Standard IRO-002 and is described in PP 905 and 906 of Order No. 693, and the second directive is applicable to Reliability Standard TOP-006 and is described in P 1660.

[35] NERC IRO Petition at 27.

projects have coordinated on a common definition of "Reliability Directive" and agreed that the IRO standard drafting team "would write the definition and post it for vetting by the industry." The definition is as follows:

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Further, the IRO-014-2 implementation plan indicates that a revised definition for "Adverse Reliability Impact" was approved by the NERC Board of Trustees on August 4, 2011; however, the petition does not discuss the merits of this change.[36] In addition, NERC does not discuss the impact of this revised definition on the overall body of Reliability Standards.

24. NERC requests that all requirements except proposed Reliability Standard TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter twelve months following applicable regulatory approval.[37] NERC also requests that Requirements R1 and R2 of proposed Reliability Standard TOP-003-2 become effective the first day of the first calendar quarter ten months following applicable

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[36] Adverse Reliability Impact (ARI) - Previous Definition - The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection. ARI – Revised Definition – The impact of an event that results in the Bulk Electric System instability or Cascading.

[37] NERC also requests that the existing TOP Reliability Standards be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following applicable regulatory approval.

regulatory approval. NERC explains that the twelve month period is to allow for entities to update processes and train operators on the revised requirements, and the two month differential for proposed Reliability Standard TOP-003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.[38]

B. NERC's IRO Petition (Docket No. RM13-15-000)

25. Also on April 16, 2013, NERC submitted for Commission approval four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators).[39] NERC also requests approval of the implementation plan for the proposed IRO Reliability Standards, and approval of the retirement of six currently-effective Reliability Standards, effective at midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a final rule in this proceeding.[40] NERC indicates that its petition also addresses two

[38] NERC TOP Petition, Exh. C at 2.

[39] NERC states that the NERC Board of Trustees approved a proposed Reliability Standard IRO-001-2 Reliability Standard on August 4, 2011, that was subsequently revised before it was filed at the Commission. The revision is designated as Reliability Standard IRO-001-3, was approved by the Board on August 16, 2012, and is included in this petition for approval. NERC IRO Petition at 4 n.5.

[40] NERC proposes to retire Reliability Standards IRO-001-1.1 (Responsibilities and Authorities); IRO-002-2 (Facilities); IRO-005-3a (Current Day Operations); IRO-014-1 (Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators); IRO-015-1 (Notifications and Information Exchange Between Reliability Coordinators); IRO-016-1 (Coordination of Real-time Activities Between Reliability Coordinators).

Order No. 693 directives associated with Reliability Standard IRO-005-1, but that it does not address a directive associated with Reliability Standard IRO-002-1 because this directive falls under the scope of Real-Time Tools Best Practices Task Force.

26. NERC identifies two "overall reliability benefits" of the proposed IRO Reliability Standards: (1) delineating a "clean division of responsibilities" between the reliability coordinator and transmission operator, giving the reliability coordinator authority to direct transmission operators to take actions to prevent or mitigate Interconnection Reliability Operating Limits (IROLs); and (2) "raising the bar" on IROL/SOL monitoring to focus on only those important to reliability. NERC also identifies four "improvements" reflected in the proposed IRO Reliability Standards, as follows:

- Interconnected bulk electric systems will be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
- Personnel responsible for planning and operating interconnected bulk electric systems will be trained, qualified, and have the responsibility and authority to implement actions.
- The security of the interconnected bulk electric systems will be assessed, monitored and maintained on a wide-area basis.
- Plans for emergency operation and system restoration … will be developed, coordinated, maintained and implemented.[41]

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[41] NERC IRO Petition at 11.

<u>IRO-001-3 (Responsibilities and Authorities)</u>

27. NERC proposes to replace the nine currently-effective requirements of Reliability Standard IRO-001-1 with the following three requirements in proposed IRO-001-3:

> **R1.** Each Reliability Coordinator shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.
>
> **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's direction unless compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform as directed in accordance with Requirement R2.

NERC states that these requirements ensure that reliability coordinators "have the responsibility and authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact."[42] According to NERC, these proposed requirements "ensure that the responsibility and authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact is assigned to the Reliability Coordinator."[43]

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[42] NERC IRO Petition at 12.

[43] NERC IRO Petition at 12-13.

28. NERC states that the changes to the proposed Reliability Standard IRO-001-3 are a result of the proposed retirement of the currently-effective Reliability Standard IRO-001-1.1, Requirement R7, which is now covered in proposed Reliability Standard IRO-014-2.[44] According to NERC, Reliability Standard IRO-014-2 will continue to ensure that both coordination agreements are in place to require that IROLs and SOLs are managed, and that system conditions that could cause Adverse Reliability Impacts are mitigated.

IRO-002-3 (Analysis Tools)

29. NERC proposes two new requirements pertaining to analytical tools and to retire Requirements R1 through R7 of currently-effective Reliability Standard IRO-002-2. The two proposed requirements provide:

> **R1.** Each Reliability Coordinator shall provide its System Operators with the authority to approve, deny or cancel planned outages of its own analysis tools.
>
> **R2.** Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

30. NERC states that the currently-effective requirements contain redundancies, which the proposed revision are intended to eliminate. NERC states that it revised Requirement R8 and incorporated it into proposed Requirements R1 and R2 of Reliability Standard

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[44] Currently-effective Requirement R7 states: The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.

IRO-002-3. NERC also indicates that it is developing a set of Reliability Standards in Project 2009-02, that will establish requirements for the functionality, performance, and maintenance of real-time monitoring and analysis capabilities which affects Reliability Standard IRO-002.

IRO-005-4 (Current Day Operations)

31. NERC proposes the following two new requirements for proposed Reliability Standard IRO-005-4:

> **R1.** When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
>
> **R2.** Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated.

32. NERC states that proposed Reliability Standard IRO-005-4 is a result of eliminating redundancies between existing and proposed standards. NERC also states that the requirements are to "ensure that entities are notified when an expected or actual event with Adverse Reliability Impacts is identified."[45]

IRO-014-2 (Coordination Among Reliability Coordinators)

33. NERC proposes the eight requirements of Reliability Standard IRO-014-2 to replace the currently-effective Reliability Standards IRO-014-1, IRO-015-1 and

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[45] NERC IRO Petition at 28.

IRO-016-1. NERC states that proposed Reliability Standard IRO-014-2 ensures that each reliability coordinator's operations are coordinated to avoid an Adverse Reliability Impact on other reliability coordinator areas and to preserve the reliability benefits of interconnected operations. Proposed Reliability Standard IRO-014-2 provides in part:

> **IRO-014-2 R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following:
>
> > **1.1.** Communications and notifications, including the mutually agreed to conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
> > **1.2.** Energy and capacity shortages.
> > **1.3.** Planned or unplanned outage information.
> > **1.4.** Control of voltage, including the coordination of reactive resources.
> > **1.5.** Coordination of information exchange to support reliability assessments.
> > **1.6.** Authority to act to prevent and mitigate system conditions which could cause Adverse Reliability Impacts to other Reliability Coordinator Areas.
> > **1.7.** Weekly conference calls.
>
> **R5.** Each Reliability Coordinator, upon identification of an Adverse Reliability Impact, shall notify all other Reliability Coordinators.
>
> **R6.** During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.
>
> **R7.** During those instances where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact, the Reliability Coordinator that identified the Adverse Reliability Impact shall develop an action plan to resolve the Adverse Reliability Impact.

34. NERC states that Requirement R1 is the same as the currently-effective requirement except for the addition of Part 1.7, which requires reliability coordinators to

have weekly conference calls. Additionally, while Requirement R1 of Reliability Standard IRO-014-1 addresses "Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability," NERC states that proposed Requirement R1 defines specific information that is to be included in the procedures, processes, and plans.

IRO Implementation Plan

35. NERC proposes as the effective date for Reliability Standard IRO-001-3, the first day of the second calendar quarter beyond the date that the standard is approved by the Commission. NERC states that this time will allow applicable entities adequate time to develop the documentation and other evidence necessary to exhibit compliance with the requirements. NERC proposes as the effective date for Reliability Standards IRO-002-3 and IRO-005-4 the first day of the first calendar quarter following the effective date of a final rule because the revisions are "to an existing mandatory and enforceable standard, applicable entities are already complying with the existing standard."[46]

36. For proposed Reliability Standard IRO-014-2, NERC proposes the first day of the first calendar quarter that is twelve months following the effective date of a final rule as the effective date. NERC states that, while the revisions to this Reliability Standard are to an existing mandatory and enforceable standard, "applicable entities should only have

[46] NERC IRO Petition, Exh. A at 8.

to make minor revisions to their Operating Plans, Operating Processes or Operating Procedures to show compliance."[47]

37. NERC also proposes retirement of the six IRO Reliability Standards, effective at midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a final rule.

C. Proposed Revisions to Reliability Standard TOP-006-3 (Docket No. RM13-12)

38. On April 4, 2013, NERC proposed revisions to Reliability Standard TOP-006-3 to divide the reporting responsibilities of balancing authorities and transmission operators into separate requirements. According to NERC, the proposed revisions clarify that transmission operators are responsible for monitoring and reporting available transmission resources, while balancing authorities are responsible for monitoring and reporting available generation resources. NERC states that this division is consistent with the roles and responsibilities of registered entities as set forth in NERC Reliability Functional Model.

39. NERC states that, as currently written, Requirement R1.2 could be interpreted as duplicating efforts to monitor and report the availability of generation and transmission resources. NERC explains that it specifically requires both transmission operators and balancing authorities to inform reliability coordinators and other affected transmission operators and balancing authorities of all transmission and generation resources available

[47] NERC IRO Petition, Exh. A at 8-9.

for use. To address these concerns, NERC revised Requirement R1.2 to limit a transmission operator’s monitoring and notification obligations to transmission resources available for use. NERC created Requirement R1.3 to limit a balancing authority’s monitoring and notification obligations to generation resources available for use. NERC explains that proposed Requirement R1.3 only requires balancing authorities to inform reliability coordinators of all generation resources available for use, and they are not required to report the availability of generation resources to transmission operators because transmission operators already receive this information from generator operators pursuant to currently effective Requirement R1.1. According to NERC, by defining the reporting channels from transmission operators and balancing authorities to reliability coordinators, reliability coordinators will receive necessary information in advance, as part of their operating tools, processes and procedures, to prevent and mitigate emergency operating situations in real and next day operations.

40. In addition, NERC proposes to modify currently-effective Requirement R3. According to NERC, while the currently-effective Requirement R3 requires reliability coordinators, transmission operators and balancing authorities to provide appropriate technical information concerning protective relays to their operating personnel, NERC states that it does not impose explicit geographical boundaries on the scope of this obligation. NERC indicates that revised Requirement R3 specifies that the relevant protective relays are those within these entities’ respective reliability coordinator area, transmission operator area or balancing authority area.

41. NERC has proposed medium Violation Risk Factors (VRFs) for proposed TOP-006-3, Requirements R1.2, R1.3 and R3 because these three Requirements all ensure that critical reliability parameters are monitored in real-time. NERC also states that the proposed Violation Security Levels (VSLs) for Requirement R1.3 meet NERC's VSL guidelines. NERC requests that the revisions become effective on the first day of the first calendar quarter after applicable regulatory approval.

II. <u>Discussion</u>

42. Pursuant to section 215(d) of the FPA, we propose to remand NERC's proposed revisions to the TOP and IRO Reliability Standards (Docket Nos. RM13-14-000 and RM13-15-000). While we believe that NERC's approach of condensing the requirements and removing redundancies generally has merit, we are concerned that, unlike the currently-effective TOP Reliability Standards, there is no requirement in the proposed standards for transmission operators to plan and operate within all SOLs. Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area. As described below, this was a problem during the Southwest Outage when the loss of a 500 kV line in Arizona Public Service's area overloaded equipment, which ultimately resulted in a cascade outage

leaving approximately 2.7 million customers without power.[48] The provisions in the proposed TOP Reliability Standards that require transmission operators to operate only within a subset of SOLs offsets the potential benefits the proposed Reliability Standards may otherwise provide.

43. The Commission believes that NERC's proposal for the treatment of SOLs affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11. Section 215(d)(4) requires that the Commission remand to the ERO for further consideration a Reliability Standard "that the Commission disapproves in whole or in part."[49] Thus, notwithstanding the organizational and administrative improvements contained in other provisions of proposed TOP Reliability Standards, our concern regarding the treatment of SOLs provides us no option other than to propose to remand the entire Reliability Standards TOP-001-2 and TOP-002-3.

44. In addition to addressing the SOL issue in the TOP Reliability Standards, we also propose to direct that NERC, on remand, develop modifications to the IRO Reliability Standards to ensure that reliability coordinators continue to develop and implement comprehensive generation and transmission outage coordination processes.

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[48] 2011 Southwest Outage Blackout Report at 1.

[49] 16 U.S.C. 824o(d)(4) (2012) (emphasis added).

45. Given that the SOL and outage coordination process issues pertain to numerous requirements across the proposed standards, the interrelationship among the TOP standards and between the TOP and IRO Reliability Standards, and that NERC requests that both sets of standards be addressed together, we propose to remand the entire set of TOP and IRO Reliability Standards.[50] This approach will give industry and NERC flexibility to develop modifications to the standards that address the concerns identified in this NOPR.

46. Further, the Commission discusses below certain provisions of NERC's proposal that require clarification or further technical explanation. Depending on the explanations provided by NERC and other interested entities in comments to this NOPR, additional Commission action may be appropriate, including the identification of additional issues that NERC must address on remand.

47. Finally, pursuant to section 215(d) of the FPA, we also propose to approve NERC's proposed revisions to Reliability Standard TOP-006-3. We find that proposed TOP-006-3 is sufficiently separate from the standards we propose to remand above. Below, we discuss: (A) the proposed TOP Standards; (B) the proposed IRO Standards; and (C) the proposed revisions to Reliability Standard TOP-006-3.

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[50] NERC TOP Petition at 1-2.

A. TOP Reliability Standards

1. Issue to be Addressed

a. Plan and Operate Within All SOLs

NERC Petition

48. Currently-effective Reliability Standard TOP-002-2a, Requirement R10 requires the transmission operator to plan to meet all SOLs and IROLs. Similarly, currently-effective Reliability Standard TOP-004-2, Requirement R1 requires transmission operators to operate within all IROLs and SOLs.

49. Proposed Reliability Standard TOP-002-3, Requirement R2 provides that each transmission operator still plan to operate within all IROLs but within only a sub-set of SOLs. It states that each transmission operator "shall develop a plan to operate within each [IROL] and each [SOL] which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator area" as a result of its Operational Planning Analysis performed in Reliability Standard TOP-002-3, Requirement R1.

50. NERC states that it is appropriate to limit Requirement R2 to a sub-set of "non-IROL SOLs" that are important to local areas and that the identified subset of non-IROL SOLs will be subject to the requirements of the proposed Reliability Standards. NERC states that non-IROL SOLs are typically thought of in terms of "equipment damage or

[element] loss of life" and are restricted to a limited or local area.[51] According to NERC, the standard drafting team concluded that it is not necessary to monitor all non-IROL SOLs because the "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue."[52] NERC explains that the "difference between non-IROL SOLs and IROLs is expressed in the difference between the consequences to the System (or impact to reliability) should unplanned perturbations of the system occur when the limit is being exceeded."[53] According to NERC, the consequences of exceeding an IROL are described as cascading, uncontrolled separation, or instability.[54] NERC states that the impact of exceeding a non-IROL SOL will not result in an Adverse Reliability Impact.[55]

Commission Proposal

51. The Commission is concerned with NERC's proposal because, unlike the currently-effective TOP Reliability Standards, the proposed standards do not require the

[51] NERC states that the revised TOP requirements move the standards to where the NERC Operating Guidelines intended them to be and ensure that the reliability of the interconnected system will be maintained and even enhanced because system operators will not be distracted from true reliability issues by local system issues. NERC TOP Petition at 18.

[52] NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on Second Draft of Standards for Real-Time Operations) at 23.

[53] NERC TOP Petition at 19.

[54] *Id.*

[55] NERC TOP Petition at 19.

transmission operator to plan and operate within SOLs, only non-IROL SOLs that are identified by the transmission operator as supporting reliability internal to its area and identified as a result of an Operational Planning Analysis.[56] For example, non-IROL SOLs that appear to be excluded from the proposed standard are non-IROL SOLs that are in a transmission operator's area that impact another transmission operator's area or more than one transmission operator's area.

52. During deteriorating system conditions, an SOL can rapidly degrade into an IROL. Limiting the requirement for transmission operators to analyze and operate within SOLs only to non-IROL SOLs identified by the transmission operator for its internal area can reduce system reliability because operators have less situational awareness of the system and conditions. Even if we accept the argument that our rules for operating bulk electric facilities should not be concerned with "equipment damage or [element] loss of life," NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL

[56] NERC's Functional Model states one of the tasks of transmission operations is to "[d]evelop system limitations such as System Operating Limits…and operate within those limits." NERC's "Reliability Functional Model Function Definitions and Functional Entities Version 5" at 37 *available* at www.nerc.com.

SOLs exceedances until the system cascaded.[57] Thus, while non-IROL SOLs are essentially defined as not posing a risk of cascading outages, instability or uncontrolled separation if they are exceeded, experience indicates that operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability. The Commission believes that when any facility ratings or stability limits are exceeded or expected to be exceeded (i.e. causing a SOL or an expected SOL on jurisdictional facilities), these conditions should be mitigated to avoid the possibility of further deteriorating system conditions and a cascade event.

53. We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

54. Moreover, we believe that proposed Reliability Standard TOP-002-3, Requirement R1 is flawed because the transmission operator should have an operational plan to operate within all Bulk-Power System IROLs and SOLs for all cases when facility ratings or stability limits are exceeded during anticipated normal and contingency event conditions. The operational plan is needed to ensure the transmission operator operates

[57] *See* 2003 Northeast Blackout Report at 74 and the 2011 Southwest Outage Blackout Report at 1.

in, or can return its system to, a reliable operating state. For example, the 2011 Southwest Outage Blackout Report raised a similar concern, stating that transmission operators should "ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency."[58] We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state. Absent such plans, system conditions can linger in an unsecure or emergency state exposing the system to cascading outages upon the next contingency. Thus, we are concerned that Requirement R1 is insufficient for the fundamental operation of the interconnected transmission network as proposed by NERC.

55. Similarly, proposed Reliability Standard TOP-001-2, Requirements R8 through R11 address transmission operator notification, operation and action with respect to IROLs and some SOLs based on the transmission operator's next-day Operational Planning Analysis. Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional

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[58] Southwest Outage Blackout Report (Recommendation 13 at 90). In addition, in Order No. 693 the Commission stated that operational plans for all IROLs should include the "[i]dentification and communication of control actions [to system operators] that can be implemented within 30 minutes" following a contingency to return the system to a reliable operating state...." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1601.

SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. Another example is if an unplanned outage of a transmission element or generator unit occurred after the completion of the next-day Operational Planning Analysis, this condition may result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now possibly exceeded due to the change in the system topology (i.e. transmission element outage) or generation dispatch (i.e. generator unit outage) that redirected the power flow on some portions of the interconnected transmission network.[59] Thus, there are various reasons why a SOL could occur in real-time operations due to the dynamic nature of the real-time interconnected transmission network and not be identified in the next-day Operational Planning Analysis. To assure that transmission operators are equipped to react to such

[59] This condition was identified in the 2011 Southwest Outage Blackout Report, which found that Imperial Irrigation District did not perform a separate, updated next-day study and contingency analysis for September 8, 2011 and instead, referenced a previous study which was not valid because it did not match the load and generation dispatch for the day. 2011 Southwest Outage Blackout Report, Recommendation No. 1 at 66.

situations, we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

56. Accordingly, pursuant to section 215(d)(4) of the FPA, we propose to remand proposed Reliability Standards TOP-001-2 and TOP-002-3. Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon. Our concerns discussed above apply to specific provisions of proposed TOP-001-2 and TOP-002-3. However, as explained above, we propose to remand proposed Reliability Standards TOP-001-2 and TOP-002-3. Moreover, as explained above, because the TOP standards are so interrelated, we also propose to remand Reliability Standard TOP-003-2 to give NERC and industry flexibility to address our concerns.

2. TOP Reliability Standards – Issues Requiring Clarification

a. System Models, Monitoring and Tools

NERC Petition

57. NERC proposes to retire TOP and IRO Reliability Standards that require reliability coordinators and transmission operators to maintain and use certain models and analysis capabilities and monitoring. NERC proposes to delete requirements for transmission operators to (1) "maintain accurate computer models utilized for analyzing and planning system operations"; (2) "use monitoring equipment to bring to the attention of operating personnel important deviations"; (3) "use sufficient metering … to ensure accurate and timely monitoring"; and (4) "have sufficient information and analysis tools to determine the cause(s) of SOL violations…."[60] NERC explains that these transmission operator requirements are unnecessary because transmission operators meet these requirements as part of NERC's certification process or are in other currently-effective or proposed standards.[61]

58. Similarly, NERC proposes to retire Reliability Standard IRO-002-2 Requirements R4, R5, R6, and R7, which address real-time monitoring and analysis capabilities and functions required to enable the reliability coordinator to perform its responsibilities. According to NERC, these requirements are unnecessary because they are inherent in the

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[60] *See* Reliability Standards TOP-002-2.1b, Requirement R19, TOP-006-2, Requirement R5, TOP-006-2, Requirement R6, and TOP-008-1, R4, respectively.

[61] NERC TOP Petition, Exhibit J at 22, 34, 35, and 38.

reliability coordinator's duty to maintain area control error or operate within IROLs/SOLs and can be verified in the certification process.[62] NERC also states that the Commission directives in Order No. 693 applicable to a minimum set of analytical tools and applicable to reliability coordinators and transmission operators will be addressed in Project 2009-02 - Real-time Monitoring and Analysis Capabilities – that has a projected completion date of 2014. Further, NERC proposes to retire other requirements of currently-effective Reliability Standard TOP-006-2 which address real-time monitoring responsibilities of the transmission operator.

Commission Proposal

59. In Order No. 693, the Commission directed NERC to develop requirements for a minimum set of analytical tools (analysis and monitoring capabilities) to ensure that a reliability coordinator has the tools it needs to perform its functions.[63] In its TOP Petition, NERC discusses the importance of analytical tools and real-time monitoring noting that, "[a]ccording to the August 2003 Blackout Report, a principal cause of the August 14, 2003 blackout was a lack of situational awareness, which was in turn the

[62] Section 500 of NERC's Rules of Procedure provide for an organization certification program that is intended to ensure that the an applicant to be a reliability coordinator, balancing authority or transmission operator "has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational." NERC Rules of Procedure at 44.

[63] Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 905, 906, 1660.

result of inadequate reliability tools."[64] We agree with NERC's statement and believe this is an area of reliability that requires vigilance. Moreover, our view is reinforced by the 2011 Southwest Outage Blackout Report, which found that "[a]ffected TOP's real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems" and consequently recommended that "TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems."[65]

60. Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process,[66] we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. Monitoring and assessment capabilities must adapt to assess changing topography and system conditions so that

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[64] NERC TOP Petition at 10. NERC also states that "the failure of control computers and alarm systems, incomplete tool sets, and the failure to supply network analysis tools with correct System data on August 14, contributed directly to this lack of situational awareness. Also, the need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations."

[65] 2011 Southwest Outage Blackout Report at 88 and Finding 12. In addition, the 2011 Southwest Outage Blackout Report , Finding 27 (at 111) states that "[a] TOP did not have tools in place to determine the phase angle difference between two terminals of its 500 kV line after it tripped."

[66] NERC TOP Petition, Exh. J at 33.

operators can continually maintain an adequate level of situational awareness. In contrast, certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

61. In addition, as discussed above, NERC indicates that Standards Project 2009-02, Real-time Monitoring and Analysis Capabilities, will address the Commission directives in Order No. 693 that address a minimum set of analytical tools. According to NERC, this project has a projected completion date of 2014. NERC's retiring of current IRO and TOP requirements that address monitoring and analysis capabilities warrants expedition in the completion of Project 2009-02. The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02.[67] Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

[67] NERC's "Standards Independent Experts Review Project" (Industry Experts Report) identifies one aspect of Project 2009-02 as a "high priority" gap. Industry Experts Report at Appendix F. The Industry Experts Report (App. F) identifies a high priority gap for Project 2009-02 to define the requirements for EMS RTCA models or performance expectations of the models; the Report also says proposed TOP-002 should incorporate current requirement for tools to determine cause of SOL violations.

b. Compliance with Reliability Directives

NERC Petition

62. Currently-effective Reliability Standard TOP-001-1, Requirements R3 and R4 require applicable entities to comply with transmission operators' and reliability coordinators' "reliability directives," which currently is an undefined term. NERC proposes Reliability Standard TOP-001-2, Requirement R1 which requires applicable entities to comply with transmission operators' "Reliability Directives," which NERC proposes to define as "[a] communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."[68]

63. In its implementation plan, NERC states that it is not proposing any new definitions but that the TOP standard drafting team coordinated with the IRO drafting team to develop a definition of "Reliability Directive." This definition is included in the IRO implementation plan.

Commission Proposal

64. The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. Also IRO Reliability Standards use the term "reliability directive" in the

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[68] NERC's proposed definition of Reliability Directive does not appear in the TOP Petition. Rather, NERC proposes the definition in the IRO Petition, Exhibit C at 1 (IRO Implementation Plan).

same manner as an undefined term.[69] In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network. NERC staff has noted in the context of how to communicate such directives that operating practices for such directives should be consistent, no matter what type of operating condition (normal, alert, emergency) exists.[70] Moreover, the transition from normal to emergency operation can be sudden and indistinguishable until recognized, often after the damage is done.[71]

65. NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding

[69] *See* Reliability Standard IRO-002-2, Requirement R8.

[70] *See* COM-003-1, Operations Communications Protocols White Paper, May 2012 at 12, *available* at nerc.com.

[71] *See* NERC staff's letter to "Project 2009-22 Interpretation of COM-002-2 R2 for IRC Drafting Team" dated November 18, 2011, at 1, *available* at nerc.com.

the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

66. In addition, while NERC has included the proposed definition in its implementation plan, NERC has not explained or justified its request for approval of the revised definition. The Commission has held that definitions are standards.[72] Therefore, we cannot approve the definition without a technical justification.

c. Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

NERC Petition

67. In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

[72] As with Reliability Standards, the Commission reviews and approves revisions to the NERC glossary pursuant to FPA section 215(d)(2). Further, the Commission may direct a modification to address a specific matter identified by the Commission pursuant to section 215(d)(5). *See also* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1893-98.

Commission Proposal

68. It is unclear whether NERC's proposal would require transmission operators to include updated external networks to reflect operating conditions external to their systems and (internal and external) sub-100 kV facilities in their operational planning analyses. In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…."[73] The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.[74] Although proposed Reliability Standard TOP-002-3, Requirement R1 requires the transmission operator to consider "projected System conditions," it is unclear whether "projected System conditions" include the relevant updated external networks and (internal and external) sub-100 kV facilities.

69. The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating

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[73] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1624.

[74] 2011 Southwest Outage Blackout Report, Recommendations Nos. 2 and 3.

conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

d. Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

NERC Petition

70. NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.[75] Proposed Requirement R7 requires each transmission operator to not operate outside any identified IROL "for a continuous duration exceeding its associated IROL T_v." Proposed Requirement R9 states each transmission operator shall not operate outside any SOL identified in Requirement R8 "for a continuous duration that could cause a violation of the Facility Rating or Stability criteria upon which it is based." Further, NERC proposes to replace Reliability

[75] NERC TOP Petition, Exhibit J at 25.

Standard TOP-008-1, Requirement R4 with multiple proposed requirements from proposed Reliability Standards TOP-001-2, TOP-002-3, and TOP-003-2. Reliability Standard TOP-008-1, Requirement R4 requires that the transmission operator have information and analysis tools to determine the causes of SOL violations, such as a most severe single contingency event, and conduct this analysis in all operating timeframes.

71. With regard to unknown operating states, currently-effective Reliability Standard TOP-004-2, Requirement R4 states that, if a transmission operator "enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes."[76] Order No. 693 directed NERC to modify Requirement R4 to restore the system "to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes."[77]

72. In the TOP Petition, NERC proposes to replace Requirement R4 with proposed Reliability Standard TOP-001-2, Requirements R7 through R11. Requirements R7 through 11 address the transmission operator's responsibilities over IROLs or SOLs that have been identified by the transmission operator as necessary to support reliability internal to its transmission operator area. NERC explains that the proposed requirements "do not include an explicit reference to 'unknown state' since system limits can and

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[76] Reliability Standard TOP-004-2, Requirement R4.

[77] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1636.

should be determined and conditions can be monitored to know when they have been exceeded."[78] NERC also states that unknown operating states "cannot exist because valid operating limits have been determined for all facilities in a TOP's footprint."[79] In addition, NERC states that the proposed requirements "prohibit operations outside of IROLs, or SOLs identified in TOP-001-2…."[80] Further, NERC explains that proposed Reliability Standard EOP-001-2, which applies to emergency operations planning, covers the general intent of being prepared to react to "Emergencies."[81]

Commission Proposal

73. NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency, to move quickly from an "unknown operating state" to within proven limits, and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed

[78] NERC TOP Petition, Exhibit H at 5.

[79] NERC TOP Petition, Exhibit I at 4.

[80] NERC TOP Petition, Exhibit H at 5.

[81] NERC TOP Petition, Exhibit I (Resolution of Order No. 693 directives) at 4.

replacement standards compare in meeting the same objectives as the current standards. We request comment on these concerns, as elaborated below.[82]

74. In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.[83] How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules? For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation? If so, is the difference significant for reliability purposes? Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability? Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the

[82] The 2011 Southwest Outage Blackout Report indicated that the September 8, 2011 cascade event "showed that the system was not being operated in a secure N-1 state" and that "[NERC's] mandatory Reliability Standards…require that the BES be operated so that it generally remains in a reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency." 2011 Southwest Outage Blackout Report at 5.

[83] Currently-effective Reliability Standard IRO-008-1, Requirement R2 requires that "[e]ach Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs."

proposed rules allow doing so while the current rules do not? Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially? Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

75. With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. In addition, a transmission operator could operate in an unanalyzed or unstudied state (as a result of loss of EMS facilities that meter and report voltage, MW flow and other key system indicators). For example, the 2011 Southwest Outage Blackout Report found that Western Area Power Administration-Lower Colorado was operating in an "unknown state" when it lost its real-time contingency analysis capabilities and, at the same time, did not notify its reliability coordinator to assist with situational awareness.[84] In light of

[84] 2011 Southwest Outage Blackout Report, Recommendation 15, at 95 states that "[a]n entity should never be operating in an unknown state, as WALC [Western Area Power Administration-Lower Colorado] was when it lacked functional RTCA [real-time contingency analysis] and State Estimator, and did not ask any other entity to assist it with situational awareness." *Cf*. NERC Compliance Filing, Docket No. RM06-16-000 (Oct. 31, 2008) at 7 ("the Reliability Coordinators in the West operate only to study conditions and note that they do not operate in IROL conditions, only SOLs, unless there are one or more unanticipated outages. In these cases, when an IROL condition is

(continued…)

this concern, the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement. As above, our main question is whether the proposed rules are comparable to the current rules for reliability purposes and, if not, whether the difference is reasonable.

e. <u>System Protection Coordination</u>

<u>NERC Petition</u>

76. NERC proposes to replace currently-effective Requirements R2, R5 and R6 in Reliability Standard PRC-001-1, with proposed Reliability Standard TOP-003-2, Requirement R5.[85] Currently-effective Reliability Standard PRC-001-1, Requirement R2 requires generator operators and transmission operators to notify affected entities of relay or equipment failures and if the failure reduces system reliability, take corrective action as soon as possible. Requirement R5 requires generator operators and transmission operators to coordinate changes in generation, transmission, load or operating conditions with appropriate advance notice that could require changes in the protection systems of others. Requirement R6 obligates transmission operators and balancing authorities to

experienced, the Reliability Coordinators must restore the system to a known operating state within 20 minutes for stability concerns and 30 minutes for thermal concerns.”).

[85] NERC TOP Petition, Exhibit J at 40 and 41. According to NERC (petition at 4), the “corresponding changes in proposed PRC-001-2 are administrative in nature and are limited to removal of three requirements in currently-effective PRC-001-1 that are now addressed in proposed TOP-003-2, included herein for approval.”

monitor the status of each special protection system in their area and to notify affected transmission operators and balancing authorities of a change in status.

77. Proposed Reliability Standard TOP-003-2, Requirement R5 states that entities "receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data." In the standard development process, the standard drafting team explained that a "data specification" is required to contain all of the information that a transmission operator and balancing authority needs to fulfill its obligations.[86] In addition, the standard drafting team stated that the transmission operator and balancing authority "are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading."[87] The standard drafting team indicated that "an auditor can only question what is contained in the requirements and in this case that

[86] *E.g.,* NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on the 7th Draft) at 72. Southwest Power Pool Regional Entity stated that it "does not believe TOP-003-2 addresses the requirements in PRC-001." Exh. D at 73. Texas Reliability Entity states that "Requirements R2, R5 and R6 of PRC-001-1, which are proposed to be deleted, are not actually replaced by any new or revised requirements in other standards, resulting in reliability gaps." Exh. D at 89.

[87] NERC TOP Petition, Consideration of Comments (Consideration of Comments on the 7th Draft) at 79. Southwest Power Pool Standards Review Group states that "[t]o be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements." *Id.*

would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards."[88]

Commission Proposal

78. The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal.[89] Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.[90]

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[88] NERC TOP Petition, Consideration of Comments (Consideration of Comments on the 7th Draft) at 88. Southwest Power Pool Standards Review Group states that "incorporating protective relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification." *Id.* at 79.

[89] In Order No. 693, the Commission required changes to Requirement R2 of Reliability Standard PRC-001-1 to clarify "corrective action" (i.e., return a system to a stable state), specify time limit for notification, and require corrective action as soon as possible but no longer than 30 minutes. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1441, 1445 and 1449.

[90] In Order No. 693, the Commission directed NERC to develop a modification to Reliability Standard TOP-006-1 to clarify "the meaning of 'appropriate technical information' concerning protective relays" so that "operators can make better informed decisions. An example of such information would be the allowable reclosing angle set in the existing relays and the maximum angle at specific points in the Bulk-Power System that would be acceptable to allow closing of lines during system restoration." Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1663 and P 1665.

f. Notification of Emergencies

NERC Petition

79. Currently-effective TOP Reliability Standard TOP-001-1a requires each transmission operator to inform its reliability coordinator and other potentially affected transmission operators "of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency."[91] In its petition, NERC proposes to retire Reliability Standard TOP-001-1a and proposes as replacements Requirements R3-R6 of Reliability Standard TOP-001-2. In particular, Requirement R3 provides "[e]ach Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis."[92] In addition, Requirement R3 has a time horizon of "Operations Planning," which NERC describes as the "operating and resource plans from day-ahead up to and including seasonal" and does not include same-day operations or real-time operations.[93]

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[91] Reliability Standard TOP-001-1a, Requirement R5.

[92] The NERC Glossary defines Operational Planning Analysis as "[a]n analysis of the expected system conditions for the next day's operation... (That analysis may be performed either a day ahead or as much as 12 months ahead.). Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints."

[93] *See* NERC Time Horizons at 1, *available* at http://www.nerc.com/pa/Stand/Resources/Documents/TimeHorizons.pdf at 1.

Commission Proposal

80. NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.[94] Indeed, during the standard development process, similar concerns were expressed.[95]

81. Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. Proposed TOP-001-2, Requirement R5, states that "[e]ach [TOP] shall inform its [RC] and other [TOPs] of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas…." The definition of Adverse Reliability Impact in NERC's TOP filing is "[t]he impact of an event that results in frequency related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that

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[94] An "anticipated" emergency should apply to all operational time horizons: operations planning, same-day, and real-time. Further, an "actual" emergency could only occur during the real-time operational time horizon.

[95] NERC TOP Petition, Exh. D, Consideration of Comments (Consideration of Comments on the 7th Draft) at 21: "R3 seems to be missing some words…it is not clear if this requirement is supposed to be about planning ("expected to be affected by anticipated Emergencies") or real-time operations ("known to be affected by actual Emergencies") or both. If the latter is intended, the Time Horizon should include Real-Time Operations and Same Day Operations…." The standard drafting team responded that "it is clear as to what needs to be communicated." *Id.* at 23.

affects a widespread area of the Interconnection."[96] In contrast, NERC defines Emergency as "[a]ny abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

82. While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion.[97] We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time

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[96] NERC TOP Petition at 19. In the IRO Petition, NERC cites a different definition of Adverse Reliability Impact: "[t]he impact of an event that results in Bulk Electric System instability or cascading." NERC IRO Petition at 13, n20.

[97] NERC TOP Petition, Exhibit C at 3.

horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

83. In addition, as noted above, NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. NERC has not explained the intent or effect of the two definitions, and the term is used in several provisions of the proposed TOP and IRO Reliability Standards. The Commission seeks clarification and a technical explanation from NERC and other interested entities regarding the two definitions, including if it is proposing a revised definition, which definition it is proposing. In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

g. Primary Decision-Making Authority for Mitigation of IROLs/SOLs

84. NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

85. NERC states in its TOP Petition that "[t]he responsibility for monitoring and handling IROLs is primarily given to the Reliability Coordinator, but the Transmission Operator has the primary responsibility to designate any SOLs that require special

attention."[98] Likewise, NERC also states that an improvement resulting from the changes to the IRO Reliability Standards is that they delineate a clean division of responsibilities between the reliability coordinator and transmission operators to "help to ensure that the Reliability Coordinator is responsible for identifying and controlling operations associated with IROLs and the Transmission Operator is responsible for identifying and controlling operations associated with SOLs."[99] Proposed Reliability Standard IRO-001-3, Requirement R1, provides that each reliability coordinator "shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact." Further, currently-effective Reliability Standard IRO-009-1, Requirement R4 states that "[w]hen actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_v."[100]

86. However, proposed Reliability Standard TOP-001-2, Requirement R11 provides similar authority for the transmission operator with respect to IROLs. NERC proposes

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[98] NERC TOP Petition at 15.

[99] NERC IRO Petition at 5-7.

[100] Reliability Standard IRO-009-1, Requirement R4.

that each transmission operator "shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8."[101]

87. NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act.[102] Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

B. IRO Reliability Standards

88. As discussed above, because of the interrelationship of the TOP and IRO Reliability Standards, the Commission proposes to remand proposed IRO Reliability Standards: IRO-001-3, IRO-002-3; IRO-005-4; and IRO-014-2. In addition, as discussed below, as part of the remand, the Commission proposes to direct that NERC develop modifications with regard to planned outage coordination. We also seek comment from NERC and other interested entities regarding several proposed provisions

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[101] NERC's TOP Petition (at 15) states that "the delineation in the proposed TOP Reliability Standards with respect to operating within an identified IROL…is an important distinction in the proposed TOP Reliability Standards that is necessary for reliability."

[102] NERC in its 2009 filing to revise and add new IRO standards (RM10-15-000 petition at 8) states that under its "Functional Model, the reliability coordinator is the functional entity with the highest level of responsibility and authority for the real-time reliability of the bulk power system."

of the IRO Reliability Standards. Depending on the responses in the NOPR comments, the Commissions may issue further directives in the final rule in this proceeding.

1. Issues to be Addressed

a. Planned Outage Coordination

NERC Petition

89. In its IRO petition, NERC proposes to retire Reliability Standard IRO-005-3.1a, Requirement R6, which requires reliability coordinators to "coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes."[103] NERC states that the "coordination aspects of this part of Requirement R6 are addressed in the requirements of currently-effective IRO-008-1,[104] Requirement R3, and IRO-010-1a, Requirement R3," which provide:

> **IRO-008-1, R3.** When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
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> **IRO-010-1a, R3.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and

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[103] NERC IRO Petition at 33-34.

[104] NERC IRO Petition at 34.

information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

Commission Proposal

90. The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.[105]

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[105] The Independent Experts Report identifies outage coordination as one of the key areas where risk to the Bulk-Power System is not adequately mitigated. Industry Experts Report at 15. The Independent Experts Report proposes (Appendix H) to fill this gap "by giving the Reliability Coordinator the authority and responsibility to develop and implement a generation and transmission outage coordination process across Transmission Operators and Balancing Authorities in their footprint" and "between its adjacent Reliability Coordinators." Industry Experts Report at 31. This outage coordination process "shall cover the time period from the current operating hour out through at least 36 months." In addition, The 2011 Southwest Outage Blackout Report

(continued…)

91. Because outage coordination is critical to operations planning and the reliability coordinator has the needed wide-area view for operations planning, on remand, the Commission proposes to direct NERC to develop modifications to the IRO Reliability Standards that would require the reliability coordinator to have the authority and responsibility to develop and implement a generation and transmission outage coordination and planning process across transmission operators and balancing authorities in its footprint and between its adjacent reliability coordinators for the operations planning timeframe.[106]

2. IRO Reliability Standards – Issues Requiring Clarification

a. Use of a Secure Data Network

NERC Petition

92. Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC

(at 67) found a problem with Imperial Irrigation District's lack of awareness of another entity's planned generation outage.

[106] This proposed directive is consistent with the Order No. 693 directive for NERC to modify Reliability Standard TOP-003-1, Planned Outage Coordination, to require communication of scheduled outages to affected entities well in advance. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1620 through P 1624. In addition, the Commission has a similar concern with proposed Reliability Standard TOP-003-2 because it is not clear whether it addresses planned outage coordination.

Rules of Procedure, Section 1002 (Reliability Support Services).[107] NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3.

Commission Proposal

93. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

94. A secure network is essential to prevent unauthorized access to or modification of information that is critical for interconnected transmission network reliability functions performed by reliability coordinators. Therefore, we seek comment and technical explanation from NERC and other interested parties regarding how the identified section in the Rules of Procedure and Reliability Standard IRO-014-2, Requirements R1, R2, and

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[107] NERC IRO Petition at 16, quoting section 1002 of the NERC Rules of Procedure which states in part that "NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC states that it will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service."

R3 ensure that the data exchange and notifications will be conducted using a secure mode in a secure environment.

b. Reliability Coordinator Monitoring of SOLs and IROLs

NERC Petition

95. NERC proposes to retire Reliability Standard IRO-002-2, Requirements R4 through R7, which require reliability coordinators to monitor IROLs and SOLs. Requirement R5 requires reliability coordinators to monitor bulk electric system elements that could result in SOL or IROL violations. NERC argues that it is appropriate to retire these requirements because: (1) an SOL is unlikely to have an impact on the wide-area reliability of the Bulk-Power System as it will generally not have an impact outside the affected transmission operator's area and (2) Requirement R4 is redundant with the requirements contained in existing Reliability Standards IRO-010-1a, and EOP-008-1.[108] NERC also asserts that these requirements are redundant with proposed Reliability Standard TOP-001-2, Requirements R8 through R11.

Commission Proposal

96. Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2

[108] NERC IRO Petition at 19-24.

Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

97. The reliability coordinator's monitoring function is important to ensure that the reliability coordinator can identify, assess and take appropriate action so that elements of the system do not operate outside established limits causing cascading outages or blackouts. Thus, monitoring is not simply a support function but a major reliability activity necessary to maintain situational awareness and ensure reliable operation of the interconnected transmission network. As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because an SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator.

98. Notwithstanding these concerns, currently-effective Reliability Standard IRO-003-2, Requirements R1 and R2 address the concern over monitoring of SOLs and IROLs, which provide:

> **R1**. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.
>
> **R2**. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or

> IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

Thus, the Commission seeks comment on whether the currently-effective Reliability Standard IRO-003-2 Requirements R1 and R2 require reliability coordinators to monitor all SOLs and IROLs.

C. Proposed Revisions to Reliability Standard TOP-006-3

99. Pursuant to section 215(d)(5) of the FPA, we propose to approve NERC's proposed revisions to Reliability Standard TOP-006-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We believe that the proposed revisions reasonably clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources is reasonable. Further, NERC's proposed revision to TOP-006-3 is consistent with the Commission's approval of NERC's approach to ensure that reliability entities have clear decision-making authority and capabilities to take appropriate actions with a clear division of responsibility with respect to balancing authority and transmission operator responsibilities during a system emergency.[109]

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[109] *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, 136 FERC ¶ 61,176 (2011).

III. <u>Information Collection Statement</u>

100. The Commission's information collection requirements are typically subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[110] However, by remanding the TOP and IRO Reliability Standards, any information collection requirements are unchanged. With regard to proposed Reliability Standard TOP-006-3, the Commission estimates that the information collection burden will not change as compared to the currently-effective standard. The reporting requirements for transmission operators and balancing authorities remain unchanged because the new requirements clarify the existing standard that the transmission operators report transmission information, while the balancing authorities report generation information.

IV. <u>Environmental Analysis</u>

101. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[111] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or

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[110] 44 U.S.C. 3507(d) (2012).

[111] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

procedural or that do not substantially change the effect of the regulations being amended.[112] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

102. The Regulatory Flexibility Act of 1980 (RFA)[113] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[114] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[115] The RFA is not implicated by this NOPR because the Commission is proposing to remand the TOP and IRO Reliability Standards and not proposing any modifications to the existing burden or reporting requirements. With no changes to the TOP and IRO Reliability Standards as

[112] 18 CFR 380.4(a)(2)(ii).

[113] 5 U.S.C. 601-612.

[114] 13 CFR 121.201.

[115] *Id.* n.22.

approved, the Commission certifies that this NOPR will not have a significant economic impact on a substantial number of small entities.

103. In addition, for proposed Reliability Standard TOP-006-3, the Commission estimates that there will be no material change in burden for all small entities because the effect of the changes merely clarify that transmission operators are responsible for reporting transmission information while balancing authorities are responsible for reporting generation information.

VI. Comment Procedures

104. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER]**]. Comments must refer to Docket No. RM13-15-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

105. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

106. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

107. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

108. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

109. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

110. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Monitoring System Conditions - Transmission Operations Reliability Standard	Docket No. RM13-12-000
Transmission Operations Reliability Standards	Docket No. RM13-14-000
Interconnection Reliability Operations and Coordination Reliability Standards	Docket No. RM13-15-000

MOTION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TO DEFER ACTION

Pursuant to Rule 212 of the Federal Energy Regulatory Commission's ("FERC" or "the Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.212, the North American Electric Reliability Corporation ("NERC")[1] hereby submits this Motion to Defer Action on NERC's request to approve revisions to the Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards until **January 31, 2015**.

I. BACKGROUND

On April 5, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that Transmission Operators are responsible for monitoring and reporting available transmission resources and that Balancing Authorities are responsible for monitoring and reporting available generation resources.

On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection

[1] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR addressing the three petitions noted above (the TOP-006-3 petition, the TOP Standards petition, and the IRO Standards petition), which proposes to approve the proposed TOP-006-3 standard but remand the proposed TOP and IRO Standards.[2] In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."[3] For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.[4]

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2 *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013)("NOPR").

3 NOPR at P 4.

4 NOPR at P 4.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[5]

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
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III. MOTION

Consistent with NERC's responsibility as the Electric Reliability Organization ("ERO") to develop Reliability Standards that provide for an adequate level of reliability of the Bulk-Power System, NERC respectfully requests that the Commission defer action in this proceeding to allow NERC time to consider the reliability concerns raised by the Commission in the NOPR. With respect to the proposed TOP and IRO Standards, NERC recently commissioned an independent review of its Reliability Standards, which also noted concerns with the TOP and IRO Reliability Standards submitted in this proceeding.[6] Specifically, the independent review identified the proposed TOP-001-2 (Transmission Operations), PRC-001-2 (System Protection

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[5] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

[6] *Available at*: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

Coordination), IRO-001-3 (Responsibilities and Authorities), and IRO-005-4 (Current Day Operations) as high risk standards requiring improvement.[7] Given these concerns, and the issues identified by the Commission in the NOPR, revisions to the proposed Reliability Standards may be required. Accordingly, NERC requests that the Commission defer action in this proceeding until **January 31, 2015**.[8]

NERC recognizes that proceeding through the administrative process of responding to the NOPR, especially given the concerns articulated by the Commission, will require a significant effort by NERC and industry. While this exercise is not without merit, a more efficient use of industry, NERC, and FERC's resources is to first examine the technical issues in the standards through NERC-led technical conferences with active industry and FERC participation. As described in **Attachment A**, NERC will hold two technical conferences to identify and assess concerns regarding the TOP and IRO Standards, such as the monitoring of SOLs, unknown operating states, and outage coordination. Concurrently, NERC will work with the NERC Standards Committee to re-formulate a standard drafting team to begin development work on revisions to the proposed standards, which would be informed by the technical conferences. Additionally, in response to the concerns noted by the Commission in the NOPR on the development of a minimum set of analytical tools (analysis and monitoring capabilities) to ensure that a Reliability Coordinator has the tools it needs to perform its functions ("Real-Time Tools"), NERC will continue development of standards that address Real-Time Tools as they relate to the proposed TOP and IRO standards, which could continue to be included as part of

7 The complete *Standards Independent Experts Review Project* report is available at: http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.

8 With respect to the proposed TOP-006-3 Reliability Standard, while the Commission raised no significant concerns in the NOPR related to this standard, NERC requests that this Motion to Defer Action also apply to that pending standard given that it was addressed by the Commission in the same NOPR as the proposed TOP and IRO standards. NERC will re-file the proposed TOP-006-3 standard for approval separate from this proceeding.

Project 2009-02, Real-time Monitoring and Analysis Capabilities, or in revisions to the proposed TOP and IRO standards. Conforming changes to standards outside of the scope of this proceeding may be required depending on the extent of the changes made to the proposed TOP and IRO Standards.[9]

Deferring action on the NOPR until January 31, 2015 will provide NERC time to hold the technical conferences and develop any necessary revisions to the TOP and IRO standards for Commission approval. While a deferral until January 31, 2015 may seem extended at first glance, the proposed schedule is compressed given the complexity of these highly technical issues and the necessity to reach consensus through the standard development process. Given the scope of the work and the need for a deferral of Commission action on these standards, NERC commits to providing the Commission with quarterly reports regarding the status of revisions.

Accordingly, given the concerns articulated by the Commission in the NOPR, NERC respectfully requests an opportunity to work with industry and FERC to analyze the concerns and propose a new path forward. This Motion to Defer Action, if granted, would provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR, would afford time to review the proposed TOP and IRO Standards through the NERC standards development process, and would help the industry, NERC, and FERC work toward a common set of solutions to develop a set of standards that are technically justifiable and important for reliability.

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[9] For example, in order to address the Commission's concerns with respect to the requirement in the proposed standards that a Transmission Operator must only provide notification of SOLs identified in a next-day Operational Planning Analysis rather than in the same-day or real-time operational time horizon, changes may need to be made to other IRO standards outside the scope of this proceeding.

IV. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission defer action in this proceeding until **January 31, 2015**.

Respectfully submitted,

/s/ Holly A. Hawkins

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Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
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Counsel for the North American Electric Reliability Corporation

December 20, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 20th day of December, 2013.

/s/ Holly A. Hawkins

Holly A. Hawkins

Counsel for North American Electric Reliability Corporation

ATTACHMENT A

Monitoring System Conditions – Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

DRAFT Technical Conference Agenda

I. The Need for Revisions to the TOP and IRO Reliability Standards

- Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013)
  - Proposed directives

II. Technical Issues

- System Operating Limits
  - Plan and Operate within all System Operating Limits
    - 30 Minute Timeframe or T_m concept

- System Models, Operating and Tools
  - Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating Status
  - Analysis capabilities in Real-time operations
  - Are requirements for monitoring necessary in standards or is certification a sufficient backstop for this capability?

- Primary Decision-Making Authority for Mitigation of Interconnection Reliability Operating Limits/System Operating Limits
  - Does the Reliability Coordinator have sole responsibility for IROLs?

- Planned Outage Coordination

- Use of the term ‘Reliability Directive’

Standards Announcement

Technical Conferences on R Revisions to TOP and IRO Standards

Comment Period Now Open through March 24, 2014

Now Available

NERC recently held two technical conferences to obtain industry input on issues identified in the Federal Energy Regulatory Commission's (FERC) notice of proposed rulemaking (NOPR) proposing to remand standards pertaining to real-time operations and reliability coordination (TOP and IRO standards). In response to this NOPR, NERC filed a motion requesting that FERC defer action until January 31, 2015 to allow NERC and the industry time to consider the issues identified in the NOPR and develop revisions as needed to address them, and FERC granted NERC's motion.

Two presentations from these technical conferences are posted on the Project 2014-03 Revisions to TOP and IRO Reliability Standards project page. The first presentation was used to facilitate a discussion of each of the issues identified in the NOPR. For each issue, a slide showing the language from the proposed standards along with a brief excerpt from the NOPR (along with the paragraph number) was prepared. The second presentation contains notes of key points from the discussion at both technical conferences, on each issue in the first presentation.

NERC is requesting industry comments on the topics discussed during the conferences or suggestions for further consideration of issues identified in the NOPR. These comments will be posted on the project webpage as part of the development record and considered by the drafting team for Project 2014-03 Revisions to TOP and IRO Reliability Standards as it develops revisions to the standards.

Please use the electronic comment form to submit comments on the issues discussed during two Technical Conferences on Revisions to TOP and IRO Reliability Standards. Comments must be submitted by **8:00 p.m. Eastern on March 24, 2014.** If you have questions please contact Ed Dobrowolski (email) or by telephone at (609) 947-3673.

If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (17 Responses)
Name (8 Responses)
Organization (8 Responses)
Group Name (9 Responses)
Lead Contact (9 Responses)
Question 1 (0 Responses)
Question 1 Comments (15 Responses)
Question 2 (0 Responses)
Question 2 Comments (15 Responses)
Question 3 (0 Responses)
Question 3 Comments (15 Responses)
Question 4 (0 Responses)
Question 4 Comments (15 Responses)
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Question 4 Comments (15 Responses)
Question 4 (0 Responses)
Question 4 Comments (15 Responses)

Individual
Thomas Foltz
American Electric Power
AEP agrees with the following comments from the Tech Conference notes (Slide #2, on Decision Authority Responsibility): * Should only be one responsible authority and that is the RC. The RC has wide-area view and ultimately can make the most reliable decisions for their applicable systems. * But TOP needs to protect its lines and RC can't push the 'button'. The TOP & RC must work together and the TOP must have some flexibility in taking actions to protect its own system. * There are times when the TOP must act quickly and coordinate with the RC after the fact (i.e. bad weather/ storm related activities). AEP agrees with the following comments from the Tech Conference notes (Slide #3, on SOL analysis): * Need more clarity on SOLs. There is not consistency among the RC's in establishing an SOL methodology or in the implementation of the methodology. The RC's SOL methodologies are not all inclusive for any facility that has a "rating" but TOPs are responsible for maintaining reliability on all facilities that have operating limits, regardless of whether they meet the RC's SOL criteria. Some SOLs overlap TOP areas and should be planned and operated accordingly. AEP agrees with the following comments from the Tech Conference notes (Slide #4, on Mitigation Plans): * SOL mitigation needs to be simple and easily understood by an operator. Additional clarity could be provided for when an SOL exceedances has occurred (pre or post-contingency). The 30 minute rule of thumb is simple for operators to understand whereas operating above an SOL for "continuous duration" could lead to ambiguities.
AEP agrees with the following comments from the Tech Conference notes (Slide #12 on Reliability Directive): * Need to provide clear guidance to operators on issue of directives – both as issuer and receiver. May need to identify as a Reliability Directive – no questions allowed, jump first and ask questions later as long as the directives do not violate any safety requirements or endanger any equipment. Need make clear for operator to communicate with accuracy and consistency.
AEP agrees with the following comments from the Tech Conference notes (Slide #6 on Unknown Operating State): * If 'unknown' remains, then it needs to be clearly described as to what it means to an operator and clear actions spelled out. If Unknown Operating State does not become a NERC defined term, the requirement should be removed. Otherwise, the industry will continue to struggle with broad interpretation of this requirement.

AEP agrees that the proposed TOP-001-2 and TOP-002-3 standards cover the proposed retirement of requirements from PRC-001-1.
AEP agrees with the fourth bullet from the Tech Conference notes (Slide #14 on Emergency notification). The TOP should notify RC of all Emergencies (based on NERC definition). The TOP and RC continuously coordinate OPA in the operational planning timeframe as well as in real time.
AEP agrees with the second bullet from the Tech Conference notes (Slide #15, Outage Coordination). Requirements inherently include coordination – A valid operating plan cannot be created without coordination. However, AEP would also support continuing the outage coordination concept somewhere in the standards.
If necessary, the topic of secure data exchange methods should be managed within the CIP standards.
Individual
Brett Holland
Kansas City Power & Light
Individual
Jo-Anne Ross
Manitoba Hydro
No comments
No comments
No comments
No comments
No comments
No comments
No comments
No comments
No comments
Individual
Patti Metro
National Rural Electric Cooperative Association (NRECA)
Group
Colorado Springs Utilities
Kaleb Brimhall
None
TOPs should have access to Real Time Contingency Analysis (RTCA), Project 2009-02 needs to move forward to fill this gap. Implementation of RTCA may take time, there are other options, possibly have the RC or BA perform this service.
RC directive should be left for each region to define via their own methodologies for the region.
The unknown state should be left the business practices of each TOP or RC and removed from standard.
PRC-001-1 R2 is applicable to reliability. The important parts of this requirement should be incorporated, as appropriate, into the applicable standards. For example, PRC-004 could incorporate the important aspects/requirements.
This is addressed in the standard EOP-001-2.1b. If the standard language is insufficient in this standard, the recommendation would be to fix it in EOP not add it in TOP/IRO.
* Outage coordination needs a lot of work to be able to fully utilize COS. RC does not currently approve/deny all outages. * Outage coordination methodology should be developed by each RC. Similar to SOL/IROL methodology
This concern should be addressed in the CIP standards under “Information Protection” requirements.
None
Group

Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
NERC proposed the retirement of Reliability Standard IRO-002-2 Requirements R4, R5, R6, and R7, which address real-time monitoring and analysis capabilities and functions required to enable the reliability coordinator to perform its responsibilities. NERC also believes these requirements are unnecessary because they are inherent in the reliability coordinator's duty to maintain area control error or operate within IROLs/SOLs and can be verified in the certification process. Likewise, Southern Company agrees with NERC and believes that there are requirements that require operation within SOLs and IROLs, which are more "results based." It is not practical to have a requirement to measure real-time monitoring nor is this necessary. The real reliability objective is to operate within identified parameters as required in IRO-005-3.1a, IRO-006_EAST-1, IRO-008-1, IROL-009-1, PER-005-1, TOP-001-2, TOP-002-2.1b, TOP-004-2, TOP-007-0, TOP-008-1, VAR-001-3, not to monitor.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
No comment.
Group
Florida Municipal Power Agency
Frank Gaffney
FMPA agrees with FERC's proposal. By retaining the requirement for TOPs to plan and operate to all SOLs for single contingencies as is required under the existing standards, the system is more resilient to contingencies beyond planning and operating single contingency criteria. SOLs can be set to Emergency Ratings which already take into account loss of life / damage considerations. Without such a requirement, what is to prevent an operator from operating in a condition where a single contingency could result in an Facility exceeding its rating to a degree where its Protection Systems operate automatically, potentially resulting in an unforeseen cascading situation. One of the purposes of PRC-023 is to prevent such automatic operation for single contingencies, but, if the system does not recognize SOLs limited by Facility Ratings, the purpose of PRC-023 can be defeated. TOP-001-2 R8 and references to it should be deleted. TOP-002-3 R2 should also be modified. FMPA does not agree with FERC's concern for single contingencies. FAC-011 makes it clear that SOLs and IROLs established must "provide BES performance" (R2) such that, "(f)ollowing … single Contingencies …, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur" (R2.2). This includes the Most Severe Single Contingency (MSSC). It also includes the time parameters of any associated Emergency Rating. As long as the TOP standards are modified to require TOPs to operate and plan within all SOL and IROLs for single contingencies, then the MSSC is covered. On whether the RC or TOP has primary responsibility for IROLs, the answer may depend on whether it is pre-contingency or post-contingency. Pre-contingency, e.g., a current day, next day or next hour analysis indicates that an IROL may be exceeded, the RC would have primary responsibility. Post-contingency where an IROL may have been exceeded as a result of multiple contingencies, FMPA would expect the TOP to react immediately in correcting the situation since time is quite short for correcting, and coordinate with the RC as time permits. FMPA agrees with the Commission's proposal to retain the requirement of the RC to monitor all SOLs. The TOP is accountable to managing SOLS; however, the RC should be responsible to monitor the performance of the TOP in performing their responsibilities.

Generally, FMPA agrees with the Commission’s proposal. FMPA believes that there ought to be recognition somewhere in the standards of multi-contingency events for which limits are not established. Although FAC-011 and FAC-014 provide for establishing limits for single and selected double contingencies, they do not provide for multiple contingencies that could occur in the operating horizon, e.g., loss of ROW, loss of substation, etc., which are beyond operating and planning criteria and will likely result in an “unknown operating state” where the operators will not know what the next single contingency will cause from a stability / voltage stability viewpoint (thermal should be known from real time contingency analysis). There ought to be a requirement somewhere for someone to figure out what is going on and take action within a specified amount of time.
In general, FMPA agrees with the Commission’s proposal. FMPA believes that TOP-003-2 lacks sufficient detail to determine the minimum amount of data and information required for reliable operation. As we have stated in past comments, we believe that TOP-003-2 ought to specify the minimum acceptable “data specification”.
FMPA agrees with FERC’s proposal, TOP’s should inform the RC (and other impacted TOPs) of all Emergencies regardless of the operating time frame, and the standard should be clarified to say as much. In addition, the term “Emergency” should be used, not “Adverse Reliability Impact”, so that it synchronizes with the definition of Reliability Directive and to avoid ambiguity.
FMPA agrees with the Commission’s proposal to retain the requirement of the RC to coordinate outages. Although proposed IRO-002-3 provides the RC the authority to cancel planned outages; the standard suffers from two primary issues: (i) the same problem as question 5 above in that IRO-010 is not specific enough to know how far in advance entities must submit their maintenance plans; and (ii) IRO-002-3 lacks sufficient detail to assure a not unduly discriminatory or preferential treatment of planned outages, as required by FPA Section 215 (d)(2). Coordination of outages, including generator outages, must be done in advance to assure a fair and equitable process in addition to assuring reliability.
Although not raised by the Commission, FMPA continues to believe that Unit Commitment, an important activity of reliable operation, will be removed from the standards with the proposed TOP/IRO standard revisions. The current BAL standards do not have a requirement for the development of a next day operating plan, as is currently required of the BA in TOP-002-2 R4. FMPA interpreted TOP-002-2 R4 as requiring the BA to have a next day operating plan that at minimum would include a plan for Unit Commitment. The proposed TOP-002-3 R1 removes the BA as an applicable entity, causing the removal of Unit Commitment requirements from the standards. In past comments, the SDT maps this BAL-002, which is incorrect since BAL-002 is real-time, not next day. It also points to BAL-001 on ACE, but, again, the requirements of BAL-001 are either real-time or 12 month rolling average which is not next day Unit Commitment. In response to comments, the SDT claims we have confused the role of the BA with the LSE; however, FMPA believes the SDT is confused. Unit commitment is to be planned by the BA, i.e., page 32 of the Functional Model, in describing the responsibilities of the BA, is to: “5. Formulate an operational plan (generation commitment, outages, etc.) for reliability evaluation.” Such responsibility that is important to the reliable operation should be within the standards. In addition to the reliability gaps identified by the Commission, FMPA believes this to be another reliability gap created by the proposed standards.
Group
Duke Energy
Michael Lowman
(1) Duke Energy believes that a common conceptual interpretation of an SOL for the Operation Planning and Real-time time horizons is needed in order to establish the foundation for the TOP/IRO standards and requirements. Currently, there is no consistent interpretation of an SOL throughout the industry. These multiple interpretations adds to the difficulty in applying a consistent approach to the definition of an SOL moving forward. (2) Duke Energy believes a TOP/RC operating in real-time with pre-contingency or post-contingency IROLs should develop and implement a mitigation plan that would mitigate the condition within 30 minutes. However, for instances where a potential SOL could be exceeded following a contingency, a TOP/RC’s mitigation plan should be developed that could be implemented in real-time within 30 minutes post-contingency.

(1) Duke Energy believes that NERC Functional Certification is enough to satisfy the Commission's concerns .
(1) Duke Energy believes that Operating Instruction during an Emergency is unclear, vague, and subject to interpretation. By using the NERC defined term of Emergency, certain tasks that Duke Energy believes is a non-emergency action would now be considered an Emergency and subject to zero tolerance. Duke submits, for consideration by the SDT, a revised definition of Emergency in an attempt to remove this ambiguity. Emergency – Any abnormal system condition that requires automatic or immediate manual action to prevent the failure of transmission facilities or generation supply that would adversely affect the reliability of the Bulk Electric System. We continue to believe that if all instances of communication from an RC/TOP to a BA, TOP, GOP, etc. is considered a directive, then it could dilute the importance of real-time emergency situations that could be dangerous for the BES. Creating and implementing a term such as Reliability Directive would actually heighten situational awareness among Entities rather than decrease it as stated by the Commission. In addition, Duke Energy believes that maintaining the language in R1 of TOP-001-2 and adding, "each Reliability Directive issued and identified as such by its Transmission Operator(s) or Reliability Coordinator, unless such action would violate safety, equipment, regulatory, or statutory requirements." as part of this requirement would provide the clarification needed by a real-time System Operator.
(1) Duke Energy is not opposed to the removal of the term "unknown operating state" from the proposed standards based on the conclusion that the term itself is essentially undefined and is interpreted differently around the industry. We feel that the idea of an "unknown operating state" is too broad in scope to be able to narrow down to a common industry definition. If a term can and is interpreted differently by each entity, it becomes more difficult to measure compliance to a standard that is based on subjectivity.
(1) Duke Energy believes that the proposal to retire certain requirements should be revisited. We are not convinced that the proposed TOP-002-3 prescribes the necessary corrective action. With that said, if PRC-001 is to remain enforceable, we suggest that a project be initiated to re-word the standard. As is written now, the wording of PRC-001 is too broad and is problematic. The phrase "reduces system reliability" as used in R2.2 and R2.3 of the currently enforceable standard is particularly broad, and should be a candidate for clarification. Lastly, if PRC-001 is to be retired, the SDT should consider revising the proposed standards to include more adequately what will be removed by PRC-001's retirement.
(1) Duke Energy is not opposed to the intent of the notification by the TOP to an RC under certain conditions. We feel that if a TOP is re-configuring and/or re-dispatching its system, that this condition would not warrant notification to an RC. However, when a TOP decides to initiate its Emergency Plan, the TOP should notify the RC of the decision. Also, we suggest that the time horizon be limited to Current Day and Next Day. We would not be supportive of a time horizon beyond Next Day.
(1) Duke Energy believes that outage coordination is an integral part of the reliability of the BES. Based on that potential impact to the BES, we believe that outage coordination should be a coordinated effort between the TOP, its RC, and affected RC(s) and explicitly addressed in the standards.
(1) Duke Energy agrees that the exchange of data should be initiated on a secure network. We believe that the SDT should review the current reliability standards, CIP and COM, as well as Standards Project 2009-02, Real-time Monitoring and Analysis Capabilities to determine if this issue has already been addressed or will be addressed in the future.
Group
Peak Reliability
Vic Howell
IROL Versus SOL Monitoring: While the determination of the existence of an IROL should be a collaborative effort between the RC and TOPs, the RC should have primary responsibility for monitoring and implementing mitigation for IROLs, while TOPs should have primary responsibility for monitoring and implementing mitigation for other SOLs. However, since any part of the BES could become an "IROL condition" as system conditions degrade, it is very difficult to draw a bright line between what the TOPs should be responsible for monitoring versus what the RCs should be

responsible for monitoring. Operating Within All SOLs: TOPs should operate within all SOLs – not just a subset of SOLs. The SDT should consider changing the standard. But even the very concept of “operating within all SOLs” means different things to different entities. SOL Confusion: There is much confusion with – and many widely varied interpretations and applications of – the SOL term. If there are inconsistencies with the interpretation and application of the SOL term, then logically, there will be inconsistencies with the notion of “establishing SOLs”, “operating within SOLs”, and “exceeding SOLs” as referenced in the Reliability Standards. Each TOP and RC may have a different idea of what it means to establish SOLs, to operate within SOLs, and to exceed SOLs. This wide variance in interpretation of the SOL concept needs to be addressed in the Reliability Standards. While some entities have suggested that the RC SOL Methodology may be able to address this, Peak believes that it is important to have NERC-wide consistency on this issue, and that the Reliability Standards are the most appropriate mechanism for that consistency. Most Severe Single Contingency: TOP-004-2 R2 states: “Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.” While the proposed language in the revised TOP standards only addresses pre-determined IROLs, TOP-004-2 R2 addresses adverse operating states for which there may be no pre-determined IROL. Removing this requirement could result in decreased reliability. Although duplication of requirements should be avoided in Reliability Standards, it is important to reliability that the Reliability Standards address both pre-determined IROLs as well as operating states where the most severe single contingency could result in Adverse Reliability Impacts. This could be addressed by either retaining the TOP-004-2 R2 language or modifying language in the proposed standards. TOP-004-2 R2 is actually better for reliability than other Reliability Standard requirements to establish and operate within IROLs. The IROL concept is “how” RCs and TOPs achieve the ultimate reliability objective (the “what”) described in TOP-004-2 R2.
A TOP cannot have true situational awareness without the awareness that tools like RTCA provide. All TOPs should know if their TOP Area is demonstrating acceptable post-contingency system performance. This will require all TOPs to have tools that have, at least, the same or similar capability as RTCA. Otherwise, there may be facilities that are not monitored for post-contingency performance, which is a significant reliability gap. Even in cases where the RC uses RTCA, the TOP must maintain primary responsibility for monitoring performance in their system. Peak Reliability would like to see the NERC Reliability Standards somehow address this significant reliability issue.
Peak agrees with the NOPR, that following Reliability Directives should be mandatory at all times, not just in cases of emergencies (or Emergencies) or Adverse Reliability Impacts. The NERC definition of Reliability Directive should be adjusted accordingly. Peak also agrees with the notes that a Reliability Directive must be identified as such in real-time in order to clearly delineate between conversations about potential actions and the actual mandatory actions associated with a Reliability Directive. Peak Reliability agrees with the technical conference notes that the NERC definition of Emergency “is broad and covers a lot of conditions –and no easy way to know when you have transitioned from normal to Emergency.” It may be beneficial to revisit the definition of Emergency.
The SDT should define "unknown operating state". If this term is not defined, then it should not be used in Reliability Standards. The parenthetical words in TOP-004-2 R4 describing an unknown operating state, “(i.e. any state for which valid operating limits have not been determined)” does not clarify the issue, but rather leads to more questions and confusion.
TOPs should be required to take action when acceptable pre- or post-contingency system performance is not happening in real-time. If the Reliability Standards are not clear on this issue, changes should be made such that this expectation is clear.
Peak Reliability agrees that the notification should not be limited to day-ahead, but should also occur as necessary in Same-Day and Real-time horizons.
Outage coordination is arguably one of the widest, most risk laden reliability gaps in the Reliability Standards. Outage Coordination expectations need to be clarified and fully addressed in the NERC Reliability Standards. RC and TOP roles and responsibilities need to be clarified. Outage Coordination is addressed in many parts of North America via tariffs, etc., so it may not be a reliability gap for some. However, the Reliability Standards should not depend on the existence of tariffs to address significant reliability issues such as outage coordination – it should be addressed in the Reliability Standards The current Reliability Standards simply do not adequately address it. Potential solution would be to create a Reliability Standard that: 1)Requires the RC to establish and document an outage coordination process for the RC Area, 2)Requires the RC’s outage coordination process

document to address a specific list of issues (much like the new MOD-001-2 R1 concept), and 3)Requires TOPs and BAs within the RC Area to follow the RC's outage coordination process.
Many of the issues surrounding the TOP/IRO efforts here are rooted in SOL and IROL concepts – operating within some SOLs but not others, delineation of responsibility between SOLs and IROLs, etc. The St. Louis and Washington DC TOP/IRO technical conferences revealed the inconsistencies and industry confusion with these terms. Considering the wide disparity and inconsistency with the use and application of the SOL and IROL terms, it is strongly suggested that the industry revisit these terms. Results Based Reliability Standards – as quoted from NERC's website: "Results based standards are standards that focus on required actions or results (the "what") and not necessarily the methods by which to accomplish those actions or results (the "how")." The SOL and IROL concept are in direct conflict with the Results Based approach. According to FAC-011-2 R2, an SOL/IROL is intended to provide a certain level of BES system performance. The SOL/IROL is the method by which ("how") acceptable system performance ("what") is achieved in real-time operations. It is a means to an end – not the end itself. "How" a TOP or RC accomplishes that reliability objective is directly determined by the tools (real-time tools or lack thereof) employed by those entities. Despite the fact that the Reliability Standards are heavily invested in the SOL and IROL terms, the relevance of these terms needs to be reevaluated, or at the very least revisited, both in definition and their use in the Reliability Standards. Doing so would result in 1) more clarity and consistency across the industry, 2) a more streamlined operational approach to achieving the ultimate reliability objective of acceptable system performance, and 3) a compliance approach that is more aligned with the Results Based concept endorsed by NERC.
Individual
Bill Fowler
City of Tallahassee
TAL agrees with the Commission's proposal in part. Many IROLs are identified for multiple conditions. While an SPS may be provided to enable controlled separation or automatic action to minimize the operators task loading, it should be clarified that the system need only be operated in real time to N-1 (and credible double) contingencies. To require operation to every conceivable IROL would unnecessarily limit use of the BES for emergency and commercial purposes. Clarity is also needed in determining "how far do we go" in determining SOL/IROLs. Any system will end up in trouble when multiple contingencies are considered. The key will be to determine what the next N-1 scenario is and prepare for it. A pre-defined IROL should not be required for a system that only shows "instability/uncontrolled separation or cascading outages" when several contingencies are stacked up. A reasonable expectation needs to be made clear and unambiguous.
While TAL agrees with the Commission, care should be taken to avoid requiring small BA/TOPs from having to obtain a Real Time CA program. Many of the entities have used the adequate modeling of the system by the RC to enable the RC to monitor the smaller system since it is not an impact to the majority of the RC Area. This practice should be allowed to continue.
TAL realizes this is a contentious area. The industry has never shown a reluctance to follow directives from the RC or a TOP. The area of concern is exposing ALL communications to be subjected to the same level of scrutiny by Compliance when there is no consideration if the action was carried out! The only concern is was 3-way communication used. If the action MUST be carried out, call it what it is, a Directive. IF there is room for negotiation, negotiate and take the proper action for the reliability of the BES. Many companies require a Directive to operate out of economics for a reliability issue in another TOPs area.
TAL believes the unknown operating state can exist during those periods that the RC's Contingency Analysis tool does not solve. If CA is solving, the state of the BES in "known". It may show some high overloads and low voltages, but it generally indicates that instability/ uncontrolled separation or cascading outages will not occur. Specific operating limits for every conceivable scenario are not necessary and do not add clarity if we are only operating to N-1 (and credible doubles). The TPL studies are good tools to be aware of what may occur, and to build certain projects, but are of little value to the real-time operation of the BES.
No comment
TAL concurs with the Commission.

TAL agrees with the commission, but not with the Independent Experts Report. Coordination of both Transmission and Generation should occur, but 36 months is excessive. Many entities do not plan that far in advance (with the exception of Nuclear Facilities). While some do plan that far in advance, they are primarily for budget purposes (major vs. minor overhaul) or to ensure vendor support/contractor schedules are coordinated. Requiring the RC to approve these at the 36 month window is an unnecessary burden on the RC with no value added to the operation of the BES. The outages do need to be coordinated as they approach the next day studies. Forced outages may affect the starting of an outage, but once you tear into a turbine, it is down for the duration of the outage.
No comments
No comments
Group
ACES Standards Collaborators
Jason Marshall
(1) While we agree with the concept of planning and operating the system within all SOLs and IROLs, the primary issue is that not all SOLs are created equal and if not implemented properly this blanket statement could reduce operational flexibility. FAC-011-2 R1.2 states that SOLs cannot exceed Facility Ratings. This creates ambiguity and confusion for operating within all SOLs. Does this mean that an SOL cannot exceed a continuous rating? If so, then the operator cannot take advantage of short-term ratings. We believe there needs to be some clarification in the FAC-011-2 standard along with the TOP standards to make it clear that exceeding a Facility Rating is not an SOL violation if the System Operator is utilizing a short term rating. (2) We agree with the concept that the RCs have primary responsibility for the reliability of the Bulk Electric System which is typically accomplished by monitoring the limits of SOLs and IROLs and in market operations directly controlling generation dispatch. In addition, we also agree that TOPs have primary responsibility for monitoring and controlling the limits of SOLs. We also agree with the technical conference comments that TOPs need to work with RCs to accomplish this task. However, this does not mean that all coordination and responsibilities need to be documented in requirements. Some could be documented in supporting documents. In many cases, RC does not have the capability or the tools to operate facilities. The TOP has this capability. In all cases (SOL, IROL) the RC should be responsible to ensure the reliability of the BES. In practice, this does not mean that the TOP will never respond to IROLs and it does not mean that the RC will not respond to SOLs. The TOP response could be included in the RC operating plans for responding to IROLs. Perhaps, the RC responsibility for SOLs would begin when certain situations arise, such as when the TOP calls upon the RC for assistance, the TOP does not respond satisfactorily to system conditions, or the SOL affects more than one TOP. There should be clear delineation of responsibilities and we recommend including examples in the technical guidance sections of the standard. (3) Because the standards already require the TOP to plan to operate within all SOLs, the standards already require the TOP to plan to operate within the most severe single contingency. A close look at the FAC standards make this clear. FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that is consistent with the established Reliability Coordinator SOL methodology. FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and stability limits while demonstrating that the BES remains stable during pre-contingent (Requirement R2, part 2.1) and post-contingent (Requirement R2, part 2.2) conditions. Requirement R2, part 2.2 would also cover the most severe single contingency. FAC-014-2, Requirement R6 compels the Planning Coordinator to identify which multiple contingencies that would result in exceedances of stability limits and to communicate the list of multiple contingencies along with the stability limits to the Reliability Coordinator. FAC-011-2 further compels the Reliability Coordinator to establish a process for identifying which stability limits associated with multiple contingencies identified by the Planning Coordinator are applicable in the operating horizon within its SOL methodology. FAC-014-2, Requirement R5, part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider. FAC-014-2, Requirement R5, part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities. Finally, the contemplated changes to proposed TOP-002-3, Requirement R2 will require the Transmission Operator to operate within SOLs. Thus, the combination of proposed TOP-002-3, Requirement R2, FAC-011-2, and FAC-014-2 cover the most severe single contingency and more.

(1) We disagree that there should be an explicit requirement to have specific tools. Requiring specific tools applies a one-size fits all approach that could have significant financial impacts on small entities. Standing up and maintaining advanced EMS functions such as real-time contingency analysis (RTCA) capability can be quite expensive for a small TOP. While we would agree that all large TOPs should have real-time contingency analysis (RTCA) capability, we question the need for RTCA capability for all small TOPs. If a small TOP is wholly contained within a large TOP and the large TOP can see into its system with it RTCA, is it really necessary for the small TOP? Furthermore, why can't the small TOP rely on its RC's RTCA results? The small TOP may also have few enough contingencies that it could complete a comprehensive deterministic study of its transmission system by enumerating all contingencies in the study so that it knows exactly what the operational impacts would be. (2) We disagree with the technical conference comments that relying on the certification process is problematic and that certification is weakened by removing requirements to have tools. If a TOP is required to operate within all SOLs, they must have the tools to determine they are operating within SOLs. When they are certified, this capability must be verified otherwise the certification process has failed. Section IV.4 of Appendix 5A – Organization Registration and Certification Manual of the NERC Rules of Procedure requires the TOP to be recertified for significant changes such as a change in footprint, relocation of a control center or replacement of an EMS. Thus, certification is designed to remain current with the TOP's capabilities. The bottom line is that if the TOP does not have the tools to give it the capability to operate within SOLs it will not. (3) Contrary to the feedback provided in the technical conference notes on slide 9, we disagree with the need for a TOP to know the cause of an SOL violation in order to act. If a TOP has a transmission line with a generator at one end and the flow on the line is exceeding the SOL, the TOP does not need to know the cause to know that redispatching the generator will mitigate the SOL. Now, the TOP may want to investigate the cause after it has mitigated the SOL violation to prevent the problem from being exacerbated further but they do not and should not wait to act until they know the cause.
We have no additional comments than those raised in the technical conference and believe the issues were captured appropriately.
(1) We do not believe it is necessary to have an explicit requirement to move from an unknown operating state to secure state because the situation would be rare, measuring compliance with such a requirement is challenging, and its covered (or will be after changes to the standards) by the requirements to operate within all IROLs and SOLs and to return they system within SOL and IROL limits. Furthermore, we believe that when a system enters an unknown operating state it is likely due to a lack of extensive study of the system and the state likely could have been known if studied. An IROL should establish boundaries of a known operating state and it should be rare to have a situation where a pre-determined IROL does not exist and the operation of the transmission system is pushed into an IROL. If the system is well studied, all IROLs should be identified. If loss of telemetry is considered an unknown state then it would be even more difficult to move to a "known" state since you cannot see into the system.
We have no additional comments than those raised in the technical conference and believe the issues were captured appropriately.
(1) We do not see significant differences between what the Commission proposed (i.e. to require the TOP to notify the RC of all emergencies regardless of time frame) and what the drafting team proposed. The primary difference seems to be in the use of Adverse Reliability Impact versus Emergency. The technical conference notes seem to capture these minor issues caused by the differences.
(1) We agree that there may not be an explicit requirement to implement an outage coordination process, however from a practical perspective it is implicitly required. First, the Operational Planning Analysis might identify a conflict that could cause an expensive cancellation of an outage. For this reason, the TOP and RC will have processes to evaluate outages further out. Secondly, the TPL standards also include a requirement (e.g. TPL-002-0b R1.3.12) to include planned maintenance. If the drafting team determines the need to add requirements for outage coordination, they should be careful to avoid creating redundancies to avoid violating P81 criteria.
(1) We believe this is an issue that should be covered by the CIP standards. It should not be covered separately in the TOP standards.
We have no additional comments. Thank you for the opportunity to comment.

Group
SPPRE
Bob Reynolds
SPPRE shares the same concerns as FERC.
There needs to be close coordination between Project 2009-02 (Real Time Reliablity Monitoring and Analysis) and the TOP/IRO Revisions project. Currently the NERC website indicates that Project 2009-02 is scheduled to be completed by 1/1/15 in line with the completion date of the TOP/IRO revisions. If these two efforts are coordinated, project 2009-02 should address the concerns expressed by FERC.
Defining both terms may reduce ambiguity
The term "unknown operating state" is ambiguous and many entities find it hard to describe what it is. There may be other ways to word the standard that address FERC's concern that are clearer.
Without a standard entities may not take corrective actions on their own.
All emergencies should be communicated between the TOP and RC.
Outage coordination needs to be included.
"via a secure network" is better addressed by the CIP Standards.
Individual
Scott Langston
City of Tallahassee
TAL agrees with the Commission's proposal in part. Many IROLs are identified for multiple conditions. While an SPS may be provided to enable controlled separation or automatic action to minimize the operators task loading, it should be clarified that the system need only be operated in real time to N-1 (and credible double) contingencies. To require operation to every conceivable IROL would unnecessarily limit use of the BES for emergency and commercial purposes. Clarity is also needed in determining "how far do we go" in determining SOL/IROLs. Any system will end up in trouble when multiple contingencies are considered. The key will be to determine what the next N-1 scenario is and prepare for it. A pre-defined IROL should not be required for a system that only shows "instability/uncontrolled separation or cascading outages" when several contingencies are stacked up. A reasonable expectation needs to be made clear and unambiguous.
While TAL agrees with the Commission, care should be taken to avoid requiring small BA/TOPs from having to obtain a Real Time CA program. Many of the entities have used the adequate modeling of the system by the RC to enable the RC to monitor the smaller system since it is not an impact to the majority of the RC Area. This practice should be allowed to continue.
TAL realizes this is a contentious area. The industry has never shown a reluctance to follow directives from the RC or a TOP. The area of concern is exposing ALL communications to be subjected to the same level of scrutiny by Compliance when there is no consideration if the action was carried out. The only concern is was 3-way communication used. If the action MUST be carried out, call it what it is, a Directive. IF there is room for negotiation, negotiate and take the proper action for the reliability of the BES. Many companies require a Directive to operate out of economics for a reliability issue in another TOPs area.
TAL believes the unknown operating state can exist during those periods that the RC's Contingency Analysis tool does not solve. If CA is solving, the state of the BES in "known". It may show some high overloads and low voltages, but it generally indicates that instability/ uncontrolled separation or cascading outages will not occur. Specific operating limits for every conceivable scenario are not necessary and do not add clarity if we are only operating to N-1 (and credible doubles). The TPL studies are good tools to be aware of what may occur, and to build certain projects, but are of little value to the real-time operation of the BES.
TAL concurs with the Commission.
TAL agrees with the commission, but not with the Independent Experts Report. Coordination of both Transmission and Generation should occur, but 36 months is excessive. Many entities do not plan that far in advance (with the exception of Nuclear Facilities). While some do plan that far in advance, they are primarily for budget purposes (major vs. minor overhaul) or to ensure vendor

support/contractor schedules are coordinated. Requiring the RC to approve these at the 36 month window is an unnecessary burden on the RC with no value added to the operation of the BES. The outages do need to be coordinated as they approach the next day studies. Forced outages may affect the starting of an outage, but once you tear into a turbine, it is down for the duration of the outage.
Group
Bonneville Power Administration
Andrea Jessup
None.
None.
BPA recognizes that while “directives” from either the TOP, RC or BA where action by the recipient is required to address emergency or adverse reliability impacts is imperative during operational emergencies, having the ability to communicate freely and comment during non-emergency and normal operating times without being bound by compliance, or having to act immediately to a specific set of instructions allows operators the sovereignty to make the best informed decision to the exact conditions of the system. BPA strongly believes that to confine all communications between parties to be strictly perceived as directives is disadvantageous, greatly reduces the ability to communicate and suffers reliability.
BPA recognizes that an unknown operating state can exist when elements are out of service and studies have to be re-established for new known limit(s). Though the removal of the term “unknown operating state” may be beneficial from a monetary perspective, BPA believes that the term “unknown operating state” is best for reliability and should be clearly defined. BPA also believes that at the moment when an element is out of service is when the “unknown operating state” begins – not after a determination has been made.
None.
None.
None.
None.
None.
Group
SPP Standards Review Group
Robert Rhodes
Regarding who’s responsible for IROLs, the RC is responsible for IROLs but the TOP should not stand back and wait for the RC to direct action on the part of the TOP. It’s a coordinated effort between the RC and TOP. To help clarify the lines of responsibility, we suggest returning the language from TOP-007-0, R4 to the proposed TOP-001-2, R10. We believe the near-IROLs should be eliminated. We should restrict ourselves to IROLs and SOLs only.
There needs to be close coordination between Project 2009-02 and the TOP/IRO Revisions project. Currently, the NERC website indicates that Project 2009-02 is scheduled to be completed by January 31, 2015 in line with the completion date of the TOP/IRO Revisions project. If these two efforts are coordinated, Project 2009-02 should address the concerns expressed by FERC.
With all the prior discussion surrounding COM-003-1 which has now morphed into COM-002-4 including the loss of the term Reliability Directive, we are a little confused as to which way to go. Some are in favor of moving on with the term Operating Instruction while others see merit in maintaining Reliability Directive. Whichever, the TOP/IRO Revisions effort needs to be closely coordinated with the Project 2007-02 effort.
The term ‘unknown operating state’ is a very ambiguous term that is so open ended, how do you ever get a handle on identifying what it really is? We suggest that we define the term within very strict criteria or eliminate it altogether.
The requirement in PRC-001-1, R2 specifically includes taking corrective action to resolve the issue but neither TOP-001-2, R5 nor TOP-002-3, R1 include taking action. The proposed requirements

require a plan and the distribution of that plan to those impacted entities but does not mention taking action to address the situation. Perhaps we simply need to incorporate that language into the requirements.
Perhaps the best thing to do in this situation is to combine R3 and R5 and specifically clarify that this crosses all time horizons. Combination was suggested at one of the conferences.
We tend to lean toward FERC's position on this topic in that previously outage coordination was right out front. With the references now wrapped up in data exchange, the coordination effort itself is somewhat obscured.
We concur with the comment from one of the conferences which asked if this wasn't a CIPs issue. If you're compliant with the CIPs standards aren't you already addressing this concern? Also, as proposed in one of the conferences, perhaps security experts should be consulted to review this issue.
Thank you for the opportunity to comment on the proceedings of the technical conferences.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
In an effort to evolve to results-based Reliability Standards, Oncor encourages the SDT to address real-time reliability monitoring and analysis capabilities by defining the results ("what") Entities are mandated to meet, and let the Entity define the "how" they meet the requirements since there is not a "one size fits all". For example, allowing the Entity to determine "how" they use their RTCA tools.
In an effort to include planned switching activities, Oncor recommends the following: A communication initiated by an RC, TOP, or BA where action by the recipient is necessary to address an Emergency, Adverse Reliability Impacts, and actions to maintain system reliability.
In an effort to evolve to results-based Reliability Standards, Oncor promotes alignment of basic functions to support the reliability of the BES. Oncor recommends any requirements regarding "secure networks" should be aligned to Communications Network Reliability Standard developed under Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions.
Individual
Michael Moltane
ITC
The Commission's proposal to treat all non-IROL SOLs as though they were IROLs for the purposes of reporting and mitigation is simply too severe, will cause undue burden, and is unnecessary to maintain the reliability of the Bulk Electric System. The Commission is absolutely correct to observe that, "if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter." Furthermore, Requirement R2 of this Standard permits each Transmission Operator to designate non-IROL SOLs for IROL treatment where the Transmission Operator deems it necessary for internal area reliability. No one is better positioned than the Transmission Owner to determine precisely which, if any, SOLs are important to internal area reliability, and Transmission Operators are more than sufficiently motivated to ensure that their system is not the source of an SOL which results outages that are significant but do not reach the threshold of an IROL (such as impacting a major sporting event, etc.). To be clear, ITC is fully supportive of Transmission Operators continuing to monitor all SOLs and for Transmission Operators to maintain mitigation plans for all SOLs; the proposed standards should be revised to reflect this. However, despite the contribution of non-IROL SOLs to the Northeast Blackout of 2003 and the 2011 Southwest Outage, ITC believes that treating each SOL as IROL will create a significant burden on the Bulk Electric System resulting from the significant amount of additional infrastructure necessary to meet such a requirements while maintaining the current level of service for customers in terms of both cost and availability. Such a requirement

would also impose a substantial additional compliance burden on registered entities without realizing a commensurate improvement in the reliability of the Bulk Electric System. Simply put, the proposal to treat all SOLs like IROLs will result in a significant increase in pre- and post-contingent load shedding, uneconomic dispatch, and reconfiguration of the Bulk Electric System until additional facilities can be put into place to meet the requirements. Transmission Operators must be given the discretion to define an appropriate mitigation strategy for each SOL reflecting the particular reliability issues associated with that SOL. Doing so would achieve the reliability gains of the Commission's proposal, but without the massively increased burden on consumers and registered entities which would result from a one-size-fits-all approach. Regarding NOPR Paragraph 87 in which the FERC asks for clarification regarding roles of the RC and TOP for IROLs, ITC believes the decision making authority for IROL's should clearly be with the RC. The TOP should coordinate with the RC as mandated by TOP-001-2 R10. The TOP should be responsible for SOLs. TOP-001-2 R 11 should be modified to clearly indicate that IROL decision making authority and responsibility lies with the RC.
ITC supports the tech conference comments that unknown state shall be defined clearly if the requirements are retained.
ITC supports the NOPR concept that the TOP should inform and coordinate with the RC on all IROL and SOL violations for all operations time horizons.
ITC agrees that since RC has the wide area view, RC should have the authority to coordinate transmission and generation outages across TOP, BA and adjacent RCs.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

Proposed Action Plan and Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Revisions pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Rationale - Changes made to the proposed definition were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. For example, analysis of phase angles may result in an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-3**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale: The Reliability Directive replaced throughout by Operating Instruction as new definition now covers SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area.

R2. Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Balancing Authority Area.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible to do due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator in Requirement R3 citing one of the specific reasons shown in Requirement R3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued in Requirement R3 citing one of the specific reasons shown in Requirement R3. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. 'Effective' added as it makes no sense to do anything unless it will be effective in mitigating the problem. 'Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures. These changes are in response to IERP recommendations.

R7. Each Transmission Operator and Balancing Authority shall assist Transmission Operators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator and Balancing Authority shall make available upon request, evidence that requested assistance was provided to other Transmission Operators unless such actions cannot be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities.

R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area .

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL Tv. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it conducted a Real-Time Assessment at least once every 30 minutes. This evidence could include, but is not limited to, dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include, but is not limited to, dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the system to within limits when an SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own monitoring and Real-time Assessment capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages of its own monitoring and Real-time Assessment capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement.

R18. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator, Balancing Authority, and Generator Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in derived limits.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, R13, and R14 through R18 and Measure M1 through M11, M13, and M14 through M18 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate an SOL exceedance as specified in Requirement R14 and Measurement M14.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act, or direct others within its Transmission Operator Area to act, to address its reliability functions within its Transmission Operator Area.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act, or direct others within its Balancing Authority Area to act, to address its reliability functions within its Balancing Authority Area.
R3	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an Operating

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-Time Operations					Instruction issued by its Transmission Operator in Requirement R3 citing one of the specific reasons shown in Requirement R3.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not provide assistance to Transmission Operators, if requested, when the requesting entity had implemented its emergency procedures, and such actions could have been physically

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one other Transmission Operator or 5% or less of the affected Transmission Operators, whichever is less, of its actual or expected operations that result in, or could result in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its actual or expected operations that result in, or could result in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its actual or expected operations that result in, or could result in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that result in, or could result in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators or more than 15% of the affected Transmission Operators, whichever is less, of its actual or expected operations that result in, or could result in, an Emergency on those respective Transmission Operator Areas when

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one negatively impacted interconnected NERC registered entity or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and telecommunication equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and telecommunication equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and telecommunication equipment, monitoring and assessment capabilities, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering and telecommunication equipment, monitoring and assessment capabilities, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R10	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.
R11	Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R13	Same-Day Operations, Real-Time Operations	High	The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes.	The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than or equal to 35 minutes and less than 40 minutes.	The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than or equal to 40 minutes and less than 45 minutes.	The Transmission Operator did not perform Real-time Assessments. OR The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than or equal to 45 minutes.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages of its own monitoring and Real-time Assessment capabilities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities.
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to operate to the most limiting parameter in instances where there was a difference in derived limits.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

White paper on SOL Exceedances to be placed here.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

Proposed Action Plan and Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 9, 2012	Adopted by Board of Trustees	Revised

4	April 2014	Revisions pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)

Rationale - Changes made to the proposed definition were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Operational Planning Analyses contain sufficient details to result in an appropriate level of situational awareness. For example, analysis of post-Contingency phase angles may result in an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service post-Contingency.

Note that ‘load’ is not capitalized in load forecast as it is the whole phrase that is the item of interest and ‘load forecast’ is not a defined term.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**

    4.1. Transmission Operator

    4.2. Balancing Authority

5. **Effective Date:**

    The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

    On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination among Reliability Coordinators) to replace six currently-effective IRO standards.

    On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale: Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis.

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale: The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

Rationale for Requirement R3: Changes in response to IERP recommendation.

R3. Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Rationale: Requirements R4 and R5 added due to IERP recommendations.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to, dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified impacted NERC registered entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to, dated operator logs or e-mail records.

Rationale for Requirements R6 and R7: Added in response to SW Outage Report recommendation 1.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to, dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to, dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted NERC registered entity or 5% or less of the impacted NERC registered entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two impacted NERC registered entities or more than 5% and less than or equal to 10% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted NERC registered entities or more than 10% and less than or equal to 15% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority does not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			notify one impacted NERC registered entity or 5% or less of the impacted NERC registered entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	notify two impacted NERC registered entities or more than 5% and less than or equal to 10% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	notify three impacted NERC registered entities or more than 10% and less than or equal to 15% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	notify four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified in Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

Proposed Action Plan and Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operational Reliability Data**

2. **Number: TOP-003-3**

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Interchange Authority

   4.6. Load-Serving Entity

   4.7. Transmission Owner

   4.8. Distribution Provider

5. **Effective Date:**

   All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale: Changes to proposed Requirement R1, part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, part 1.2 is in response to NOPR paragraph 78 on relay data. Language moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

Rationale for Requirement R5: Proposed Requirement R5, part 5.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses,

Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 – March 24, 2014

Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes "Distribution Provider" to "Transmission Service provider"	Errata
1.1	October 29, 2008	Removed "proposed" from effective date BOT adopted errata changes: updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approval	Revised
-3	August 4, 2011	Approved by Board of Trustees	
-4	April 2014	Revisions as per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose:** To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**

> **Rationale:** Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5. They do not show in this red-line as this red-line is based on IRO-001-3 as originally submitted by Project 2006-06 where they were initially removed.

4.1. Reliability Coordinator

4.2. Transmission Operator

4.3. Balancing Authority

4.4. Generator Operator

4.5. Distribution Provider

4.6. Transmission Service Provider

5. **Effective Date:**

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale: The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

R1. Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act, by issuing Operating Instructions to ensure the reliability of its Reliability Coordinator Area.

Rationale for Requirements R2 and R3: The addition of Transmission Service Provider to Requirements R2 and R3 allows for the retirement of IRO-004-2.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the specific reasons shown in Requirement R2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the reasons shown in Requirement R2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with the Reliability Coordinator's Operating Instructions, and compliance with the Operating Instructions could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction Issued by its Reliability Coordinator in Requirement R2 citing one of the reasons shown in Requirement R2.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Deleted R2, M3 and associated compliance elements Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
-3	August 4, 2011	Approved by Board of Trustees	
-4	April 2014	Revisions as per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**

2. **Number:** IRO-002-4

3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

   On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale: Requirements R1 and R2 from IRO-002-2 have been added back into IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issues. The currently-effective requirement in IRO-002-2 has been separated into two parts (Requirements R1 and R2 below) to distinguish voice and data requirements. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

R1. Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide upon request, evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators.

R2. Each Reliability Coordinator shall have data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request, evidence that could include, but is not limited to, a document that lists its data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators.

R3. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities.

> **Rationale**: Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because an SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

R4. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

> **Rationale for Requirement R5**: Requirement R5 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

R5. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M5. The Reliability Coordinator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.3. Data Retention

- The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.
- The Reliability Coordinator shall keep data or evidence for Requirements R4 and R5 and Measures M4 and M5 for the current calendar year and one previous calendar year.
- If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator does not have voice communication facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area or with neighboring Reliability Coordinators.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator does not have data link facilities with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area or with neighboring Reliability Coordinators.
R3	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

Proposed Action Plan and Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF’s based on June 24, 2013 approval.	
2	April 2014	Changes pursuant to Project 2014-03	Revise

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments

2. **Number:** IRO-008-2

3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.

4. **Applicability**

   4.1. Reliability Coordinator.

5. **Proposed Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

   On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

> **Rationale for Requirement R1**: Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to, dated power flow study results.

> **Rationale for Requirements R2, R3, and R4**: In response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

R2. Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it reviewed the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. Such evidence could include, but is not limited to, dated e-mail messages.

R3. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 and that considers the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include, but is not limited to, plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R4. Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Reliability Coordinator shall have evidence that it notified impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R5. Each Reliability Coordinator shall perform a Real-time Assessment at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M5. Each Reliability Coordinator shall have, and make available upon request, evidence to show it conducted a Real-Time Assessment at least once every 30 minutes. This evidence could include, but is not limited to, dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R6: Language changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. In Requirements R6 and R8 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M7. Each Reliability Coordinator shall have evidence that it issued Operating Instructions, as necessary, to ensure that actions were taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6. Such evidence could include, but is not limited to, dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation.

R8. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M8. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R4, R6 through R8 and Measures M1 through M4, M6 through M8 for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R5 and Measure M5 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Reliability Coordinator Wide Area will exceed any of its System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities
R3	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						of its Operational Planning Analysis as required in Requirement R1 and considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
For the Requirements R4, R6, and R9 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R4	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted NERC registered entity or 5% or less of the impacted NERC registered entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Reliability Coordinator did not notify two impacted NERC registered entities or more than 5% and less than or equal to 10% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in	The Reliability Coordinator did not notify three impacted NERC registered entities or more than 10% and less than or equal to 15% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to	The Reliability Coordinator did not notify four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s).

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				the plan(s).	their role in the plan(s).	
R5	Real-time Operations	High	The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes.	The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 35 minutes and less than 40 minutes.	The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 40 minutes and less than 45 minutes.	The Reliability Coordinator did not perform Real-time Assessments. OR The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 45 minutes.
R6	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5%	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s)

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL)	and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability	Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection	as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			exceedance within its Reliability Coordinator Wide Area.	Coordinator Wide Area.	Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	
R7	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.
R8	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.	Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. OR	Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been	the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the Emergency identified in Requirement R6 has been prevented or mitigated	The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated	prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval.	
2	April 2014	Revisions pursuant to Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.

> **Rationale:** Changes to applicability come from IRO FYRT recommendation due to needing UVLS and UFLS information in the data specification.

   4.3. Planning Coordinator.

   4.4. Transmission Planner.

   4.5. Generator Owner.

   4.6. Generator Operator.

   4.7. Load-Serving Entity.

   4.8. Transmission Operator.

   4.9. Transmission Owner.

   4.10. Distribution Provider.

> **Rationale**: The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.

5. **Proposed Effective Date:**

   Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements

Rationale for Requirement R1:

Proposed Requirement R1, part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, part 1.2 is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R1, part 1.7 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Medium	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four or more of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses,

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						Real-time monitoring, and Real-time Assessments.
R2	Operations Planning	Medium	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

G. Guidance

The term “mutually acceptable format” was the subject of a Commission-approved Interpretation. By specifying that the format must be mutually agreeable, the standard supports efficiency by precluding the submission of data that is in a format that cannot be used. If the parties cannot mutually agree on the format, it is expected that they will negotiate to reach agreement or enter into dispute resolution to resolve disagreement. While disputes may arise, the Reliability Standard does not dictate a specific dispute resolution process and leaves Reliability Coordinators and other entities options for informal resolution of a dispute on the format of data and flexibility in choosing a dispute resolution process to reach an agreement. *See Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, 134 FERC ¶ 61,213 at P 63 (2011).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" when used as adjective. 3. Changed standard header to be consistent with standard "Title." 4. Initial capped heading "Definitions of Terms Used in Standard." 5. Added "periods" to items where appropriate. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, self-certification. 8. Changed apostrophes to "smart" symbols. 9. Added comma in all word strings "Procedures, Processes, or Plans," etc. 10. Added hyphens to "Reliability Coordinator-to-Reliability Coordinator" where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06
-3	August 4, 2011	Approved by Board of Trustees	
-4	April 2014	Revisions per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators

2. **Number:** IRO-014-3

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

   On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale for Requirement R1: Grammatical changes for consistency with defined terms to Requirement R1.

Deletions are due to duplication with proposed IRO-008-2, Requirements R4 and R6 and proposed IRO-010-3.

Other changes are grammatical for clarity.

R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. Communications and notifications, and the process to follow in making those notifications.

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.

1.6. Provisions for weekly conference calls.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that impact other Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that the Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include, but is not limited to, dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

R3. Each Reliability Coordinator shall make notifications and exchange reliability–related information with other impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it made notifications and exchanged reliability–related information with impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.

R4. Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection. *[Violation Risk Factor: Lower][Time Horizon: Same-Day Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it participated in agreed upon (at least weekly) conference calls with other Reliability Coordinators within the same Interconnection.

Rationale: Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

R5. Each Reliability Coordinator, upon identification of an Emergency, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an Emergency, notified other impacted Reliability Coordinators.

R6. Each impacted Reliability Coordinator shall operate as though the problem exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

R7. Each Reliability Coordinator that identified an Emergency shall develop an action plan to resolve the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M7. Each Reliability Coordinator that identified an Emergency shall have evidence that it developed an action plan during those instances where Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation.

R8. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M8. Each impacted Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who has identified the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

Rationale for Requirement R9: Language added for consistency with proposed TOP-001-3, Requirement R7.

R9. Each Reliability Coordinator shall assist Reliability Coordinators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions cannot be physically be implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M9. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided to Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 R2, and R9 and Measures M1 M2, and M9.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirements R3, R4, and R5 and Measures M3, M4, and M5.
- Each Reliability Coordinator shall retain 3 calendar years plus current calendar year of evidence for Requirements R6, R7, and R8 and Measures M6, M7, and M8.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.6.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.6.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.6.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted Reliability Coordinators to support Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	The Reliability Coordinator has the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet one of the criteria.	The Reliability Coordinator Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet two of the criteria.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet three of the criteria.	The Reliability Coordinator does not have Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.

For the Requirements R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not make notifications and exchange reliability–related information with one impacted Reliability Coordinator in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.	The Reliability Coordinator did not make notifications and exchange reliability–related information with two impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.	The Reliability Coordinator did not make notifications and exchange reliability–related information with three impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.	The Reliability Coordinator did not make notifications and exchange reliability–related information with four or more impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.
R4	Same-Day Operations	Lower	N/A	N/A	N/A	The Reliability Coordinator failed to participate in an agreed upon (at least weekly) conference call with other Reliability Coordinators within the same Interconnection.
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an Emergency.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an Emergency.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an Emergency.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an Emergency.

R6	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the problem exists during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R7	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identified the Emergency failed to develop an action plan to resolve the Emergency during an instance where Reliability Coordinators disagreed on the existence of Emergency.
R8	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identified the Emergency during an instance where Reliability Coordinators disagreed on the existence of the Emergency.

R9	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions could not be physically be implemented or would violate safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

Proposed Action Plan and Description of Current Draft

This is the first posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Additional ballot	August 2014
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Outage Coordination**
2. **Number: IRO-017-1**
3. **Purpose:** To ensure that outages are properly coordinated.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Planning Coordinator
   - **4.5.** Transmission Planner
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel and the SW Outage Report.

B. Requirements and Measures

Rationale: This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s) prior to submitting to Reliability Coordinators.

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and generator outages within its Reliability Coordinator Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Note on part 1.5 – Operations planning horizon is next-day to one year out. This requirement part will allow for Reliability Coordinators to request seasonal planning assessments if so desired.

1.5. Document and maintain the specifications for outage analysis during the operations planning horizon.

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it followed its Reliability Coordinator outage coordination process. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R3: Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall coordinate solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	N/A	N/A	N/A	The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area
R2	Operations Planning	Low	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not follow its Reliability Coordinator outage coordination process.
R3	Operations Planning	Low	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its Planning Assessment to impacted Reliability Coordinators.
R4	Operations Planning	Low	N/A	N/A	N/A	The Reliability Coordinator, Planning Coordinator, or Transmission Planner did not coordinate solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Definitions

Project 2014-03 Revisions to TOP/IRO Reliability Standards

As part of the work in Project 2014-03 Revisions to TOP/IRO Reliability Standards, the SDT is proposing changes to two existing definitions: Operational Planning Analysis and Real-time Assessment. The two definitions are used in the following proposed standards: TOP-001-3, TOP-002-4, and IRO-008-2 and are not used in any other currently-effective standards, or standards in development in any other project.

Operational Planning Analysis

Currently-effective definition: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).*

Proposed definition: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)*

Real-time Assessment

Currently-effective definition: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.*

Proposed definition: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)"*

Rationale

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

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Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements

Existing Approved Standards

- TOP-001-1a Reliability Responsibilities and Authorities
- TOP-002—2.1b Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2a Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 Response to Transmission Limit Violations
- IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
- IRO-002-2 Reliability Coordination — Facilities
- IRO-003-2 Reliability Coordination – Wide Area View
- IRO-004-2 Reliability Coordination – Operations Planning
- IRO-005-3.1a Reliability Coordination — Current Day Operations
- IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a Reliability Coordinator Data Specification and Collection
- IRO-014-1 Coordination Among Reliability Coordinators
- IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 Operating Personnel Responsibility and Authority

Filed with FERC but not approved – these standards were filed with FERC but never approved and will be retired as part of this project, and upon Board approval of replacement standards, NERC will petition FERC to withdraw its petition for approval of these standards:

- TOP-001-2 Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data
- IRO-001-3 Reliability Coordination - Responsibilities and Authorities
- IRO-002-3 Reliability Coordination — Analysis Tools
- IRO-005-4 Reliability Coordination — Current Day Operations
- IRO-014-2 Coordination Among Reliability Coordinators
- PRC-001-2 System Protection Coordination

Prerequisite Approvals

Definition of Operating Instruction (filed with proposed COM-002-4).

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)*
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.*

	Revised definition: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective two months earlier, in order to provide recipients of data requests from their RCs, TOPs, and/or BAs time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Interchange Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Transmission Service Provider
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the standard is approved by an

applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

- **Standards for Retirement:**
  Midnight of the day immediately prior to the Effective Date in the particular jurisdiction in which the new standard or definition is becoming effective.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

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Standards Authorization Request Form

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Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the “TOP Standards”) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the “IRO Standards”) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.” For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits (“SOLs”), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the recommendations from the Independent Expert Review Project and the SW Outage Report will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards to address concerns expressed in the NOPR a. Consider the inputs from technical conferences 2. Consider the recommendations in the Independent Expert Review Report and the SW Outage Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Preserve the intent of the reliability objectives in the current, approved standards so that no reliability gaps are created 5. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 6. Address the directives from Order 693 originally assigned to Projects 2006-06 and 2007-03.

SAR Information	
7.	Address the following directive from Order 693, paragraph 1855: *"Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."*
8.	Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements.
9.	Address the issue of outage coordination as pointed out by the Independent Experts Review Panel through the creation of a new standard.
10.	Address the recommendations of the IRO Five Year Review Team (Project 2012-09) for the IRO standards revised in this project.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5 IRO-008-1 IRO-009-1 IRO-010-1a IRO-015-1 IRO-016-1	May need to be reviewed for language and terminology consistency with revisions made in this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A

Regional Variances	
SPP	N/A
WECC	N/A

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SAR Type (Check as many as applicable)			
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On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the ~~suggestions~~ recommendations from the Independent Expert Review Project and the SW Outage Report will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards to address concerns expressed in the NOPR a. ~~Use~~ Consider the inputs from technical conferences ~~to advise actions~~ 2. Consider the ~~comments and suggestions~~ recommendations in the Independent Expert Review Report and the SW Outage Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Preserve the intent of the reliability objectives in the current, approved standards so that no reliability gaps are created ~~4.~~5. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 6. Address the directives from Order 693 originally assigned to Projects 2006-06 and 2007-03.

SAR Information
~~5.~~7. Address the following directive from Order 693, paragraph 1855~~ so that all monitoring responsibilities for the Reliability Coordinator are included in the IRO family of standards~~: *"Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities*."
8. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements.
9. Address the issue of outage coordination as pointed out by the Independent Experts Review Panel through the creation of a new standard.
~~6.~~10. Address the recommendations of the IRO Five Year Review Team (Project 2012-09) for the IRO standards revised in this project.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒ ~~☐~~ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ ~~☐~~ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ ~~☐~~ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒ ~~☐~~ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ ~~☐~~ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.

Reliability Functions		
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to	Yes

Reliability and Market Interface Principles	
access commercially non-sensitive information that is required for compliance with reliability standards.	

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5 IRO-008-1 IRO-009-1 IRO-010-1a IRO-015-1 IRO-016-1	May n~~N~~eed~~s~~ to be reviewed for language and terminology consistency with revisions made in this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A

Regional Variances	
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | May 2014

This mapping document showing the translation of Requirements in the following approved, currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** Reliability Coordinators must comply with mandatory approved standards. The SDT proposes retiring the requirement, consistent with P81, as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission Operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	**Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed IRO-002-4 Requirement R1 for voice links and Requirement R2 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed IRO-002-4, Requirements R1 and R2:** **R1.** Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **R2.** Each Reliability Coordinator shall have data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **Approved PER-004-2, requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	This requirement is replaced by proposed IRO-002-4 Requirements R1 and R2. **Proposed IRO-002-4, Requirements R1 and R2:** **R1.** Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **R2**. Each Reliability Coordinator shall have data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirements R4 and R5:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	This requirement is replaced by proposed IRO-002-4, Requirement R4. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R5:** **R5**. Each Reliability Coordinator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed definition:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R4 and approved EOP-008-1, Requirement R1, part 1.6.2. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.	This requirement is replaced by proposed IRO-002, Requirement R3 and approved EOP-008-1, Requirement R1, part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R4. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R4 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels,

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect.	Replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1.8. Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The first sentence is replaced by proposed IRO-002-4, Requirement R4. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R4**: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by proposed EOP-010-1, Requirements R1 through R3. **Proposed EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R4, R6 and R8. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R8:** **R8.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R2: **R2**. Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R6.3. Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads. **R7.** Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R4 and R5. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	The first sentence is replaced by proposed IRO-002-4, Requirements R4 and R5. The second sentence is replaced by proposed IRO-010-2, Requirements R1, part 1.2, and R3. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. **Proposed IRO-010-4, Requirement R1, part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator,

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:** **R5.** If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits.
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. 10 **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses;

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	2.1.4. Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	The requirement is replaced by proposed IRO-008-2, Requirements R4, R6, and R8. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R8:** **R8**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R5. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall perform a Real-time Assessment at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R4 and R6. **Proposed IRO-008-2, Requirements R4 and R6:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). Proposed IRO-008-2, R6: **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: **R1.1.** List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. **R1.2.** Mutually agreeable format. **R1.3.** Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). **R1.4.** Process for data provision when automated Real-Time system operating data is unavailable.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **1.3** A periodicity for providing data. **1.4** The deadline by which the respondent is to provide the indicated data. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.	This requirement is replaced by proposed IRO-010-2, Requirement R2. **Proposed IRO-010-2, Requirement R2:** **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R3. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator shall make notifications and exchange reliability–related information with other Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R4. **Proposed IRO-014-3, Requirement R4:** **R4.** Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection.
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R3.1**. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	This requirement is replaced by approved PRC-001-1.1, Requirement R3. **Approved PRC-001-1.1, Requirement R3:** **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **3.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **3.2** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R5 through R8 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R5:** **R5.** Each Reliability Coordinator, upon identification of an Emergency, shall notify all other Reliability Coordinators. **Proposed IRO-014-3, Requirement R6:** **R6.** During each instance where Reliability Coordinators disagree on the existence of an Emergency each impacted Reliability Coordinator shall operate as though the problem exists. **Proposed IRO-014-3, Requirement R7:** **R7**. During those instances where Reliability Coordinators disagree on the existence of an Emergency, the Reliability Coordinator that identified the Emergency shall develop an action plan to resolve the Emergency. **Proposed IRO-014-3, Requirement R8:** **R8.** During those instances where Reliability Coordinators disagree on the existence of an Emergency, each Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency unless such actions would violate safety, equipment, regulatory or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	**R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-2, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-2, R2: **Proposed IRO-001-2, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-2, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance is provided through proposed TOP-001-3, Requirement R7. ‘Emergency’ deleted as the assistance is assistance in response to the other entities’ emergency.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R3: **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7.** Each Transmission Operator and Balancing Authority shall assist Transmission Operators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R7.1 For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – reactive power: Replaced by approved VAR-001-3, Requirement R8 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-3, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Approved VAR-001-3, Requirement R8:** **R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits. **Approved VAR-001-3, Requirement R12:** **R12**. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved IRO-009-1, Requirement R1: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall	The Transmission Operator and balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2.

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	**Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:**

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-3, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-003-3, Requirement R1, part 1.1.1, and proposed TOP-002-4, Requirement R4. **Approved INT-003-3, Requirement R1:** **R1.** Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. R1.1.1. Interchange Schedule start and end time. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing Authorities have been removed from the applicability of this requirement. SOLs and IROLs

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13, and proposed IRO-017-1, Requirement R1, part which is designed to allow the Reliability Coordinator to request seasonal studies. Second sentence – SOLs are set by the Reliability Coordinator in approved FAC-011-2, Requirement R4, part 4.3 and distributed to the Transmission Operators thus assuring that the Transmission Operators utilize the same SOLs. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed IRO-017-1, Requirement R1:** 1.5 Document and maintain the specifications for outage analysis during the operations planning horizon **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:** **2.4** Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007) **14.2** Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	**R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	The SDT believes that modeling starts with the model created by the Planning Coordinator and model verification for the Planning Coordinator is addressed in proposed MOD-033-1, Requirements R1 and R2. Therefore, the SDT is proposing to retire this requirement.

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed MOD-033-1, Requirement R1: **R1**. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: **1.1** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation; **1.2** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs; **1.3** Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and **1.4** Guidelines to resolve the unacceptable differences in performance identified under Part 1.3. **Proposed MOD-033-1, Requirement R2:** **R2.** Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, requirements R2 and R3.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels,

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved FAC-014-2, Requirement R2: **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System. **Proposed TOP-001-3, Requirement R12:** **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13.** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-3, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R12 and R14.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
6.1 Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	**R6.2** has been replaced by proposed TOP-001-3, Requirement R8. **R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, part 3.3 and to proposed TOP-003-3, Requirement R5, part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, part 3.3:** **3.3** A mutually agreeable security protocol **Proposed Top-003-3, Requirement R5, part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data**,"** unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R4, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R4: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, part 1.2; proposed TOP-003-3, Requirement R1, part 1.2; and proposed TOP-003-3, Requirement R2, part 2.2. **Proposed IRO-010-2, Requirement R1, part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-003-3, Requirement R2, part 2.2: **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10:** **R10**. Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Metering accuracy for Balancing Authorities is covered under approved BAL-005 -0.2b, Requirement R17 and thus this requirement can be retired from the TOP standards. The SDT believes that this requirement truly pertains to the Balancing Authority and that the Transmission Operator is the actual entity who will be taking care of many of the meters mentioned in approved BAL-005-0.2b. Therefore, the SDT is proposing to retire the Transmission Operator part of this requirement. **Approved BAL-005-0.2b, Requirement R17:** **R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R4, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R4**: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R10: **R10.** Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R6 and R7. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R7: **R7.** Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R7. **Proposed IRO-008-2, Requirement R7:** **R7**. Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13.** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.

NERC
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Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | May 2014

This mapping document showing the translation of Requirements in the following approved, currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** Reliability Coordinators must comply with mandatory approved standards. The SDT proposes retiring the requirement, consistent with P81, as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission Operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	**Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed IRO-002-4 Requirement R1 for voice links and Requirement R2 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed IRO-002-4, Requirements R1 and R2:** **R1.** Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **R2.** Each Reliability Coordinator shall have data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **Approved PER-004-2, requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	This requirement is replaced by proposed IRO-002-4 Requirements R1 and R2. **Proposed IRO-002-4, Requirements R1 and R2:** **R1.** Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators. **R2**. Each Reliability Coordinator shall have data links with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirements R4 and R5:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	This requirement is replaced by proposed IRO-002-4, Requirement R4. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R5:** **R5**. Each Reliability Coordinator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed definition:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R4 and approved EOP-008-1, Requirement R1, part 1.6.2. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.	This requirement is replaced by proposed IRO-002, Requirement R3 and approved EOP-008-1, Requirement R1, part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R4. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R4 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels,

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	Addition of Transmission Service Provider to proposed IRO-001-4, Requirements R2 and R3 allows for the retirement of this requirement. **Proposed IRO-001-4, Requirement R2:** R2. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-4, Requirement R3:** R3. Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the specific reasons shown in Requirement R2.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	Replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	**Proposed IRO-002-4, Requirement R5:** **R5**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The first sentence is replaced by proposed IRO-002-4, Requirement R4. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R4**: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by proposed EOP-010-1, Requirements R1 through R3. **Proposed EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R4, R6 and R8. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R8:** **R8.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels,

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads. **R7.** Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R4 and R5. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	The first sentence is replaced by proposed IRO-002-4, Requirements R4 and R5. The second sentence is replaced by proposed IRO-010-2, Requirements R1, part 1.2, and R3. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R5:** **R5.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. **Proposed IRO-010-4, Requirement R1, part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:** **R5.** If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. [10] **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses; **2.1.4.** Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	The requirement is replaced by proposed IRO-008-2, Requirements R4, R6, and R8. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R8:** **R8**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R5. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall perform a Real-time Assessment at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R4 and R6. **Proposed IRO-008-2, Requirements R4 and R6:** **R4.** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). Proposed IRO-008-2, R6: **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

<table>
<tr><th colspan="2">Standard IRO-010-1a Reliability Coordinator Data Specification and Collection</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following:

R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

R1.2. Mutually agreeable format.

R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).

R1.4. Process for data provision when automated Real-Time system operating data is unavailable.</td><td>This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3.

Proposed IRO-010-2, Requirement R1:
R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to:

1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

1.2 Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability.

1.3 A periodicity for providing data.

1.4 The deadline by which the respondent is to provide the indicated data.

Proposed IRO-010-2, Requirement R3:
R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol</td></tr>
<tr><td>R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.</td><td>This requirement is replaced by proposed IRO-010-2, Requirement R2.

Proposed IRO-010-2, Requirement R2:
R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td></tr>
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Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

<table>
<tr><th colspan="2">Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.

R1.1 The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.</td><td>This requirement is replaced by proposed IRO-014-3, Requirement R3.

Proposed IRO-014-3, Requirement R3:
R3. Each Reliability Coordinator shall make notifications and exchange reliability–related information with other Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.</td></tr>
<tr><td>R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.

R2.1 The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.</td><td>This requirement is replaced by proposed IRO-014-3, Requirement R4.

Proposed IRO-014-3, Requirement R4:
R4. Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection.</td></tr>
<tr><td>R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.</td><td>This requirement is replaced by approved PRC-001-1.1, Requirement R3.

Approved PRC-001-1.1, Requirement R3:
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

3.1 Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

3.2 Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.</td></tr>
</table>

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R5 through R8 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R5:** **R5.** Each Reliability Coordinator, upon identification of an Emergency, shall notify all other Reliability Coordinators. **Proposed IRO-014-3, Requirement R6:** **R6.** During each instance where Reliability Coordinators disagree on the existence of an Emergency each impacted Reliability Coordinator shall operate as though the problem exists. **Proposed IRO-014-3, Requirement R7:** **R7**. During those instances where Reliability Coordinators disagree on the existence of an Emergency, the Reliability Coordinator that identified the Emergency shall develop an action plan to resolve the Emergency. **Proposed IRO-014-3, Requirement R8:** **R8.** During those instances where Reliability Coordinators disagree on the existence of an Emergency, each Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency unless such actions would violate safety, equipment, regulatory or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	**R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-2, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-2, R2: **Proposed IRO-001-2, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-2, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R3: **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7.** Each Transmission Operator and Balancing Authority shall assist Transmission Operators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R7.1 For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – reactive power: Replaced by approved VAR-001-3, Requirement R8 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-3, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Approved VAR-001-3, Requirement R8:** **R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits. **Approved VAR-001-3, Requirement R12:** **R12**. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved IRO-009-1, Requirement R1: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall	The Transmission Operator and balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	**Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-3, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-003-3, Requirement R1, part 1.1.1, and proposed TOP-002-4, Requirement R4. **Approved INT-003-3, Requirement R1:** **R1.** Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. R1.1.1. Interchange Schedule start and end time. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing Authorities have been removed from the applicability of this requirement. SOLs and IROLs

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13, and proposed IRO-017-1, Requirement R1, part which is designed to allow the Reliability Coordinator to request seasonal studies. Second sentence – SOLs are set by the Reliability Coordinator in approved FAC-011-2, Requirement R4, part 4.3 and distributed to the Transmission Operators thus assuring that the Transmission Operators utilize the same SOLs. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed IRO-017-1, Requirement R1:** 1.5 Document and maintain the specifications for outage analysis during the operations planning horizon **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:** **2.4** Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007) **14.2** Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	**R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	The SDT believes that modeling starts with the model created by the Planning Coordinator and model verification for the Planning Coordinator is addressed in proposed MOD-033-1, Requirements R1 and R2. Therefore, the SDT is proposing to retire this requirement.

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Proposed MOD-033-1, Requirement R1:

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes:

1.1 Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;
1.2 Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;
1.3 Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and
1.4 Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

Proposed MOD-033-1, Requirement R2:
R2. Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.

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Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, requirements R2 and R3.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels,

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved FAC-014-2, Requirement R2: **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System. **Proposed TOP-001-3, Requirement R12:** **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13.** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-3, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R12 and R14.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
6.1 Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	**R6.2** has been replaced by proposed TOP-001-3, Requirement R8. **R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, part 3.3 and to proposed TOP-003-3, Requirement R5, part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, part 3.3:** **3.3** A mutually agreeable security protocol **Proposed Top-003-3, Requirement R5, part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data**,"** unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R4, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R4: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, part 1.2; proposed TOP-003-3, Requirement R1, part 1.2; and proposed TOP-003-3, Requirement R2, part 2.2. **Proposed IRO-010-2, Requirement R1, part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-003-3, Requirement R2, part 2.2: **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10:** **R10**. Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Metering accuracy for Balancing Authorities is covered under approved BAL-005 -0.2b, Requirement R17 and thus this requirement can be retired from the TOP standards. The SDT believes that this requirement truly pertains to the Balancing Authority and that the Transmission Operator is the actual entity who will be taking care of many of the meters mentioned in approved BAL-005-0.2b. Therefore, the SDT is proposing to retire the Transmission Operator part of this requirement. **Approved BAL-005-0.2b, Requirement R17:** **R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R4, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R4**: **R4.** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R10: **R10.** Each Transmission Operator shall monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas, as needed to maintain reliability within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R6 and R7. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R7: **R7.** Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R7. **Proposed IRO-008-2, Requirement R7:** **R7**. Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8.** Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13.** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal (continuous) and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). Typical Normal (continuous) Ratings are 24 hour ratings. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).
2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology

or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinators SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

a. The BES shall demonstrate transient, dynamic, and voltage Stability.
b. All Facilities shall be within their Normal (continuous) Facility Ratings and thermal limits.
c. All Facilities shall be within their pre-Contingency voltage limits.
d. All Facilities shall be within their Stability limits.

Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

a. The BES shall demonstrate transient, dynamic, and voltage Stability.
b. All Facilities shall be within their applicable Emergency (short-term) Facility Ratings and thermal limits.
c. All Facilities shall be within their post-Contingency voltage limits.
d. All Facilities shall be within their Stability limits.
e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that is consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this does not capture the complete intent of the SOL concept believing the intent of approved FAC-011-2 is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs include Facility Ratings (Normal (continuous) and Emergency (short-term) Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal (continuous) and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators shall establish SOLs to prevent unit/intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level for which a post-Contingency solution can be reached. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.
4. **Voltage Stability Limits:**
   Transmission Operators shall stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level for which a post-Contingency solution can be reached. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

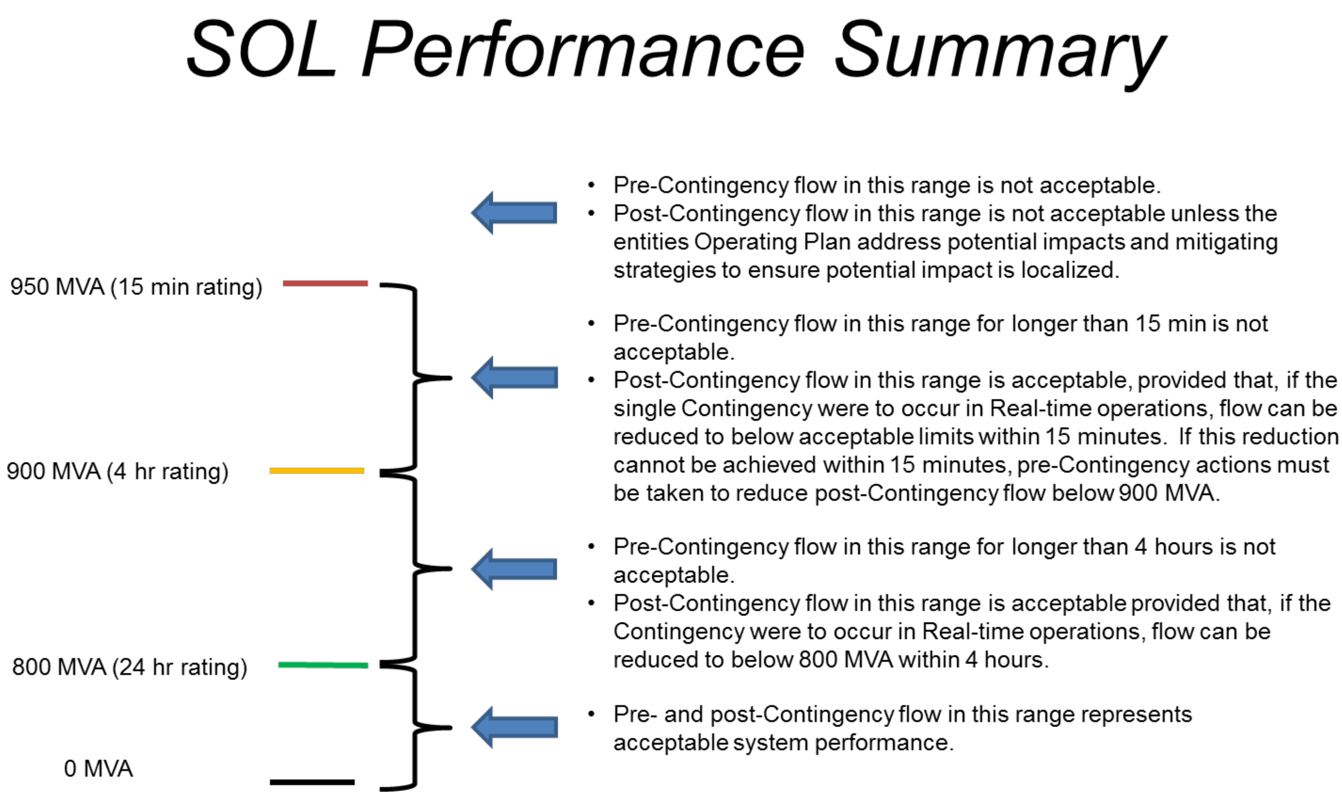
The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.

2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.



Note 1: Pre-Contingency flow is the actual MVA flow observed on the Facility through Real-time operations monitoring.

Note 2: Post-Contingency flow is the calculated MVA flow expected to occur on the Facility in response to a single Contingency as indicated by Real-time Assessments.

Note 3: 24 hour, 4 hour, 15 minute ratings are provided as an example for illustration purposes and may be different based on individual TO Rating methodologies.

Figure 1. Facility Rating System Operating Limit Performance Summary

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Both normal and emergency voltage limits are established that respect the Transmission Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

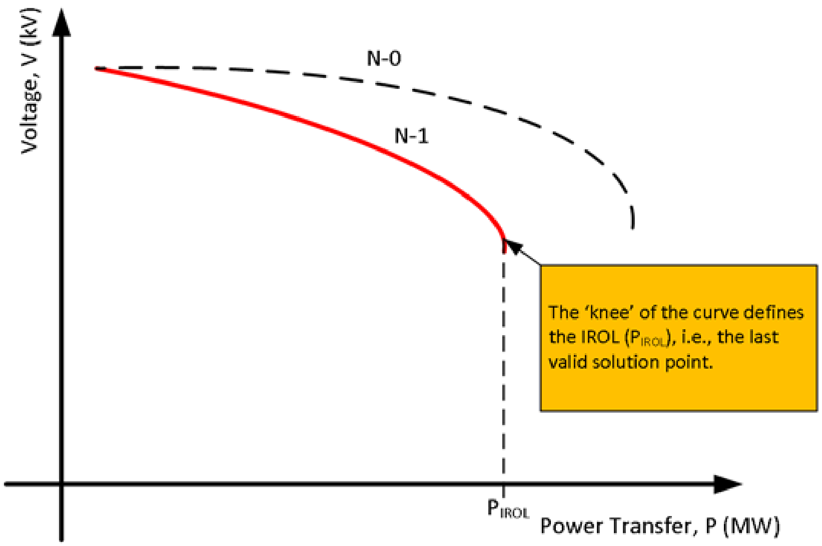


Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal (continuous) and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal Limit Exceeded	Pre-Contingency Loading	Post-Contingency Loading
Normal (24 hr)	Non-cost actions, off-cost actions, emergency procedures except load shed consistent with timelines identified in Operating Plan.	Trend – continue to monitor. Take non-cost actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.
Emergency (4 hr)	All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.	Use all effective actions and emergency procedures except load shed consistent with timelines identified in Operating Plan.
Load Shed	All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.	All of the above however, load shed only if necessary to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.

Legend
NON-COST
OFF-COST
LOAD SHEDDING

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operating to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.

- **Same-Day Operations** – routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the bulk electric system.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment, life or other physical or safety limitations for the equipment involved.

TOP/IRO Standards - Items for SDT Discussion from FERC NOPR

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

Plan and Operate within all System Operating Limits

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

SDT Consideration:

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R3: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R7: Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Proposed IRO-008-2, Requirement R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability.

Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

<u>SDT consideration:</u>

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-Time Assessment at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own monitoring and Real-time Assessment capabilities.

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

> SDT consideration:
>
> See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

> **Para 60**: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.
>
>> SDT consideration:
>>
>> With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.
>>
>>> Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.
>>>
>>> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
>>
>> With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-Time Assessment at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

SDT consideration:

See previous response.

Compliance with Reliability Directives

Para 64: The currently-effective TOP Reliability Standards use “reliability directive,” which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of “Reliability Directive” appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

SDT consideration:

The Project 2014-03 SDT is replacing the term ‘reliability directive’ with the defined term ‘Operating Instruction’ throughout the proposed standards. The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered.

Para 65: NERC’s TOP and IRO petitions do not explain the proposed, defined term “Reliability Directive,” or why compliance with a transmission operator’s directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. The proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, part 1.1 to explicitly specify that sub-100 kV data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, part 1.1: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.
>
> Proposed IRO-010-2, Requirement R1, part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT discussed this concern and concluded that an explicit requirement to use the data was an unnecessary administrative concern.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. These requirements will dictate what external data a Transmission Operator needs to acquire.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R4, part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an “unknown operating state” to within proven limits …

SDT consideration:

See previous responses for this heading.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the ‘cause’ of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to ‘fix’ the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying ‘cause’ for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

SDT consideration:

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, part 2.1) and post-contingent (Requirement R2, part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

Approved FAC-011-2, Requirement R2, and parts 2.1 and 2.2:
The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES

condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

<u>SDT consideration:</u>

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

<u>SDT consideration:</u>

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-Time Assessment at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-Time Assessment at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

<u>SDT consideration:</u>

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, part 1.6.2 covers this situation.

Approved EOP-008-1, Requirement R1, part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R5 that uses only actual and projected Emergency covering all time horizons.

Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

Proposed IRO-014-2, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s) prior to submitting to Reliability Coordinators.
1.2 Specify outage submission timing requirements.
1.3 Define the process to evaluate the impact of Transmission and generator outages within its Reliability Coordinator Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.
1.5 Document and maintain the specifications for outage analysis during the operations planning horizon.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall follow its Reliability Coordinator outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall coordinate solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, part 5.3 and proposed IRO-010-2, Requirement R3, part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, sub-100 kV data, and applicable relay data are included.

> Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Proposed IRO-010-2, Requirement R1, part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses,

Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to review next day operating plans of its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities.
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). Seasonal studies are accommodated in proposed IRO-017-1, Requirement R1, part 1.5. **Proposed IRO-017-1, Requirement R1, part 1.5:** Document and maintain the specifications for outage analysis during the operations planning horizon.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Seasonal studies are accommodated in proposed IRO-017-1, Requirement R1, part 1.5. **Proposed IRO-017-1, Requirement R1, part 1.5:** Document and maintain the specifications for outage analysis during the operations planning horizon.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). Seasonal studies are accommodated in proposed IRO-017-1, Requirement R1, part 1.5. **Proposed IRO-017-1, Requirement R1, part 1.5:** Document and maintain the specifications for outage analysis during the operations planning horizon.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability.	The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs.	Proposed TOP-003-3, Requirement R1, part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	**Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-contingency operating conditions. **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed TOP-001-3, Requirement R13**: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R14**: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures**.**	The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a	Model parameters are outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	consistent basis to make sure discrepancies do not occur.	
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for sub-100 kV data and monitoring as deemed necessary by the reliability entities. **Proposed TOP-003-3, Requirement R1, part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. **Proposed IRO-002-4, Requirement R4**: Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		and the status of Special Protection Systems in its Reliability Coordinator Area.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. **Proposed IRO-002-4, Requirement R4:** Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	(1) Phase angle calculation tools are outside the scope of this project. (2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) Seasonal studies are accommodated in proposed IRO-017-1, Requirement R1, part 1.5: Document and maintain the specifications for outage analysis during the operations planning horizon.
	TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.	Training is outside the scope of this project.

Project 2014-03 - Revision of TOP/IRO Reliability Standards

Resolution of Issues and Directives

The following table contains a list of all FERC directives, industry issues, and Independent Expert Review Panel (IERP) recommendations associated with the standards being revised in Project 2014-03, with proposed resolutions.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	892. Consider commenters' suggestions as part of the standards development process. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.	The SDT has added measures for all requirements. The Regional Reliability Organization has been removed from the standards.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	893. Consider commenters' suggestions as part of the standards development process. FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.	The SDT has considered the commenter's suggestions and believes that safety refers to any type of safety including personal or equipment and that no additional wording is necessary. If a generator receives conflicting Operating Instructions, the generator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.
IRO-001-3	FERC Order 693	895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.	The SDT has considered the comments and believes that a Reliability Coordinator can direct a Qualifying Facility (registered as a GO or GOP) to act through the issuance of Operating Instructions. Therefore, no additional requirements are necessary.
IRO-001-3	FERC Order 693	896. Eliminate the references to the regional reliability organization as an applicable entity. Paragraph 896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR	The SDT has removed all references to the Regional Reliability Organization from the standards.

Standard	Source	Language	Resolution
		proposed to direct the ERO to develop modifications to Requirement R1 to substitute "Regional Entity" for "regional reliability organization" and reflect NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	
IRO-001-3	FERC Order 693	897. Consider adding measures and levels of non-compliance. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	The SDT has added measures and Violation Severity levels (VSLs) (which replaced levels of non-compliance) for each requirement.
IRO-001-3	FERC's December 20, 2007 and April 4, 2008 Orders	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan	The SDT has established requirements that apply to the Load-Serving Entity. **Proposed TOP-001-3, Requirement R3**: Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction

Standard	Source	Language	Resolution
		describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail	issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard	Source	Language	Resolution
		marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability First (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see:	

Standard	Source	Language	Resolution
		· FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.	
IRO-001-3	Fill in the Blank Team	Remove ", sub-region, or interregional coordinating group" from R1	Terms have been removed from the standard.
IRO-001-3	Version 0 Team	Inability to perform needs to be communicated	Clarity has been provided to address this issue throughout the various standards.
IRO-001	Version 0 Team	What is meant by 'interest of other entity'?	The SDT proposes to retire Requirement R9. All Reliability Coordinator Standard Requirements are developed so that the Reliability Coordinator shall act in the interest of reliability for the Reliability Coordinator Area and the Interconnection.

Standard	Source	Language	Resolution
IRO-001-3	Fill in the Blank Team	Consider removing "Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another." from the Purpose section of the standard.	The purpose statement has been revised accordingly. Purpose: To establish the responsibility of Reliability Coordinators to act or direct other entities to act to prevent an Emergency.
IRO-001-3	NERC Audit Observation Team	All applicable registered functions shall comply with RC directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Inform the RC immediately of the inability to perform such directives. For audit purposes, what is acceptable evidence?	Measure M2 contains the provisions for suitable evidence. **Proposed IRO-001-4, Measure M2**: Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instruction, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the

Standard	Source	Language	Resolution
			Reliability Coordinator's Operating Instruction. If no event has occurred, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider may provide an attestation that an event has not occurred.
IRO-001-3	VRFs Team	R6 - Since the RC must be NERC certified, it stands to reason that anyone performing RC tasks should be certified. However, since the RC still retains the accountability for actions, and requirement 4 handles the agreements, this requirement is a medium risk.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
IRO-001-3	IERP	Requirement R1 content is incomplete. IERP recommended addressing 3 concepts as follows: RC has the authority to direct others to act. RC has the obligation to direct others to act to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.	The NERC Functional Model v5 spells out the authority of the Reliability Coordinator on page 30 under the description of the Reliability Coordinator functional entity. Proposed IRO-001-4, Requirement addresses the obligation of the Reliability Coordinator to direct others to act. **Proposed IRO-001-4, Requirement R1**: Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to

Standard	Source	Language	Resolution
		When directing others to act in accordance with this requirement, a RC must identify its directive as a "Reliability Directive". Consider consolidating with other authority-related standards and COM-003 in a single Authority standard as follows: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.	ensure the reliability of its Reliability Coordinator Area. The term 'Reliability Directive' has been replaced with the defined term 'Operating Instruction.' Proposed COM-002-4 determines the protocol for issuing Operating Instructions. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-001-3	IERP	IERP viewed Requirement R2 language as unclear and unable to be practically implemented. Questioned whether equipment requirements were a valid reason for not complying with RC direction. IERP proposed covering this requirement under a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.

Standard	Source	Language	Resolution
		implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	
IRO-001-3	IERP	IERP viewed content of Requirement R3 as incomplete by not requiring a reason for not complying with the RC's direction IERP recommended consolidating into a single Authority standard (see requirement above, which would replace both IRO-001 requirements R2 and R3)	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.
IRO-002-1	FERC Order 693	905 - Require a minimum set of tools that must be made available to the reliability coordinator. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.	The SDT revised the definition of Real-time Assessment and Operations Planning Analysis to require Transmission Operators and Reliability Coordinators to ensure that those entities will have the capabilities they need to fulfill their reliability responsibilities. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Standard	Source	Language	Resolution
			Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
IRO-002	Version 0 Team	R5 – define synchronized information system	The term is not used in the revised standards.
IRO-002	Version 0 Team	R7 – define 'adequate' tools and 'wide-area'	The terms are not used in the revised standards
IRO-002-1	Version 0 Team	Words such as 'easily understood' and 'particular emphasis' need to be tightened	The terms are not used in the revised standards
IRO-002-3	IERP	IERP viewed Requirement R1 as incomplete. RC also needs to approve any other work being done on the tools, hardware/software/telecom systems within the RC that could affect the quality and the content of the data coming into the control center.	Proposed IRO-002-4, Requirement R3 addresses this issue. **Proposed IRO-002-4, Requirement R3**: Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities.

Standard	Source	Language	Resolution
		Also consider consolidating with Project 2009-02 Requirement R1 was proposed for consolidation under a new Authority standard: Authority R2 Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.	The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-002-3	IERP	IERP viewed Requirement R2 as incomplete. Procedures need to address not only tools outages, but also tools maintenance or other inhibitors to quality performance of analysis tools. Also consider consolidating with Project 2009-02	The SDT added 'maintenance' approval to proposed IRO-002-3, Requirement R3. This includes all work being done on monitoring and analysis capabilities and not just those that will cause an outage. **Proposed IRO-002-4, Requirement R3**: Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards.
IRO-003	Order 693	914. … we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards	The term is not used in the revised standards. The proposed data specification concept allows for the Reliability Coordinator to ask for any reliability

Standard	Source	Language	Resolution
		development process to create criteria to define the term "critical facilities" in a reliability coordinator's area …	related data that it needs in order to fulfill its reliability tasks thus obviating the need for a specific criteria for determining critical facilities. And specific requirements for monitoring have been added for the Reliability Coordinator. Proposed IRO-010-2, Requirement R1: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.
IRO-004-1	Order 693	934. In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	Measures have been added to all requirements.

Standard	Source	Language	Resolution
IRO-004-1	Order 693	935. …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency	The SDT has addressed this issue in proposed IRO-008-2 and TOP-002-4 as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R3**: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified

Standard	Source	Language	Resolution
			as a result of its Operational Planning Analysis as required in Requirement R1.
IRO-005	FERC Order 693	520. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR.	The SDT addresses the need for Reliability Coordinator assessment and approval on a requirement by requirement basis. For example, see proposed IRO-008-2, Requirements R3 and R6. **Proposed IRO-008-2, Requirement R3**: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R6**: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Standard	Source	Language	Resolution
IRO-005-1	FERC Order 693	946. "Conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROLS, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to NERC.	Completed and filed in Oct 2008
IRO-005-1	FERC Order 693	950- Provide further clarification that reliability coordinators and transmission operators direct control actions, not LSEs as part of the standard development process. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.	The SDT has proposed IRO-001-4, Requirement R1 to address the Commission's suggestion for clarification. **Proposed IRO-001-4, Requirement R1**: Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
IRO-005-1	FERC Order 693	951-"Measures and levels of non-compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency, and causes of the violations and whether these occur during normal or contingency conditions. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our	The SDT has added measures and VSLs (which replaced levels of non-compliance) for each requirement.

Standard	Source	Language	Resolution
		regulations, the Commission directs the ERO to develop a modification to IRO-005-1through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions.	
IRO-005-1	Fill in the Blank Team	R14 has regional reference	The term is not used in the revised standards.
IRO-005-1	Version 0 Team	R10, 11 & 12 – RA not empowered to do this	RA is no longer an applicable entity in the revised standards.
IRO-005-4	IERP	Requirement R1 is incomplete--needs to include Emergency. Requirement R1 reads: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. Also - there are gaps between the old std IRO-005-3 R2 to IRO-005-4: missing is:	The SDT replaced Adverse Reliability Impact with Emergency in all requirements. Emergency is a broader term.

Standard	Source	Language	Resolution
		There is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. (Minus strikethrough) FROM IRO-005-3 R9: Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows.	Proposed IRO-002-4, Requirement R4 addresses the issue of monitoring. **Proposed IRO-002-4, Requirement R4**: Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area. The SDT believes all appropriate items, including Special Protection System evaluation and awareness is addressed through the revised definitions of Real-time Assessment and Operations Planning Analysis. The data specification has been revised to explicitly address Special Protection Systems. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation,

Standard	Source	Language	Resolution
		From IRO-005-3 R10: In instances where there is a difference in derived limits, the Transmission Operators,	Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) Proposed IRO-010-2, Requirement R1, part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. The SDT has addressed the issue of resolving differences in limits in proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R18**:

Standard	Source	Language	Resolution
		Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter. Recommend consolidating with IRO-008 R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits. The SDT has consolidated requirements and standards as it believes appropriate.
IRO-005-4	IERP	The proposed standard creates a gap in outage coordination by proposing to retire IRO-005-3 R6. This could be resolved through an Authority standard as proposed by the IERP From IRO-005-3 R6: The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The SDT has proposed a new standard, IRO-017-1 Outage Coordination, to address this issue.
IRO-005-4	IERP	Requirement R2 should also include Emergency Requirement R2 reads: Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and	The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency.

Standard	Source	Language	Resolution
		Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated. Note: there is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Recommend moving to IRO-008 and create an R4	
IRO-014-2	IERP	Gap in Requirement R1 - Need to identify RC's authority to direct another RC to take action - suggestion: create another Requirement, i.e., R6 (in proposed authority standard). Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT does not agree with this recommendation. A Reliability Coordinator does not direct another Reliability Coordinator. Proposed IRO-014-3 describes how to coordinate between Reliability Coordinators.
IRO-014-2	IERP	R2 is administrative and should be deleted	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R3 implements plan from R1; it should be combined with R1	The SDT believes that combining the requirements would create a complex requirement with multiple objectives that would be difficult to measure for compliance.

Standard	Source	Language	Resolution
IRO-014-2	IERP	Requirement R4 is administrative and should be deleted.	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R5 should require notification of "all IMPACTED RCs"; not "ALL"	The SDT has added 'impacted' to appropriate locations in the standards.
IRO-014-2	IERP	R6 should be consolidated with other standards that incorporate the concept of operating to the most conservative for reliability - IRO-009-1 R5 R6 reads: During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.	Approved IRO-009-1 only addresses IROLs. Proposed IRO-014-3 addresses all limits.
IRO-014-2	IERP	Requirement R7 should be retired. The reliability objective is covered under R6, and also supported by IRO-009-1 R5	The SDT believes that the two requirements are sufficiently distinct to warrant separateness. Requirement R6 speaks to actual operations. Requirement R7 speaks to having an established plan. The SDT believes that reliability is best served by having a plan to follow.
IRO-014-2	IERP	Requirement R8 should be retired. The reliability objective is covered under R6.	The SDT does not agree with this recommendation. Requirement R8 is a separate requirement.
IRO-016	VRF's Team	R1.2.1 & R2 – ambiguous	Requirement R2 was approved for retirement by FERC effective January 2014. Requirement R1, part 1.2.1 was incorporated in the set of requirements in proposed IRO-014-3, and ambiguous language has been deleted.

Standard	Source	Language	Resolution
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of “emergency” and define the criteria for entering into the various states. Also define the authority for declaring these states.	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara’s comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This concern is addressed in proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8**: Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
TOP-001-1	Version 0 Team	What is ‘clear decision making authority’?	The term is not used in the revised standards
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.

Standard	Source	Language	Resolution
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been revised to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-001-2	IERP	Requirement R1 phrase "unless it violates requirements" is too permissive or there may be a better way to phrase it Consider consolidating TOP-001-2 Requirements R1 and R2 and all other standards requirements related Authority to into a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under [Authority standard R1] unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate	The SDT believes that this is well understood language. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.

Standard	Source	Language	Resolution
		safety, equipment, regulatory, or statutory requirements.	
TOP-001-2	IERP	The language "emergency assistance" in Requirement R4 is unclear. When and how must assistance be rendered, and what type? BA's should be included as functional entity. Consider moving R4 to EOP standards (this is an "emergency" operating requirement)	The SDT revised the language for clarity and included the Balancing Authority. Proposed TOP-001-3, Requirement R7: R7. Each Transmission Operator and Balancing Authority shall assist Transmission Operators, if requested, provided that the requesting entity has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
TOP-001-2	IERP	Requirement R5 should also include notification of Emergencies (in addition to ARI), and should include Bas. R5 states: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.	The SDT added impacted Balancing Authorities. The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency. Proposed TOP-001-3, requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.
TOP-001-2	IERP	R6 needs to include real time outages of telecom as well as planned outages.	The SDT added telecommunications to the requirement.

Standard	Source	Language	Resolution
		Requirement should be covered under COM-001	Proposed TOP-001-2, Requirement R9: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. COM standards are not in scope for this project.
TOP-001-2	IERP	Requirement R8 does not cover all information needed for reliability. It should cover 1) SOLs within a TOP's/RC's footprint, 2) SOLs that are within one TOP's/RC's footprint that could affect another entity and 3) an SOL that spans into 2 TOP's/RC's footprints The requirement should also obligate the TOP to also inform impacted TOPs (The entity that could be impacted must tell the TOP that could impact them that it needs the info)	The SDT has addressed issue 1 in proposed TOP-001-3, Requirement R15. SOLs that cross boundaries are taken care of at the Reliability Coordinator level. Proposed TOP-001-3, R15: Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded.
TOP-002-3	Order 693	1597. Consider ISO-NE recommendation that the reference to "transmission service provider" in TOP-002-2 R12 be replaced by TOP and/or TO. Requirement R12 states: The Transmission Service Provider shall include known SOLs and IROLs within its	This requirement is now addressed by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included.

Standard	Source	Language	Resolution
		area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Approved MOD-028-2, Requirement R6.1: Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3**: Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. Approved MOD-030-2, Requirement R2.4: Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
TOP-002-3	Order 693	1598. Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	The data specification standard require that a Reliability Coordinator and Transmission Operator

Standard	Source	Language	Resolution
			acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. Proposed IRO-010-2, Requirement R1 and part 1.1: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and part 1.1**: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

Standard	Source	Language	Resolution
TOP-002-3	Order 693	1600. Address critical energy infrastructure confidentiality as part of the routine standard development process	The data specification standards now contain provisions for addressing security of data. **Proposed IRO-010-2, Requirement R3, part 3.3**: A mutually agreeable security protocol. **Proposed TOP-003-3, Requirement R5, part 5.3:** A mutually agreeable security protocol.
TOP-002-3	Order 693	1601. …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages	SOLs are the responsibility of the Transmission Operator and IROLs are the responsibility of the Reliability Coordinator. This issue is addressed in proposed changes to the IRO standards. **Proposed IRO-008-2, Requirement R1**: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R3**: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).
TOP-002-3	Order 693	1606. Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	The SDT agrees and has addressed the issue in proposed TOP-002-3, Requirement R4, part 4.4: Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.
TOP-002-3	Order 693	1608. Require simulation contingencies to match what will actually happen in the field	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)
TOP-002-3	IERP	Requirement R1. TOP-008-1 R4 needs to be incorporated into TOP-002-3 requirement R1. Also - the definition of "Operational Planning Analysis" provides too much latitude in time. Recommend removing the parenthesis in the definition; the entity will make the determination and document (documentation is evidence) the applicability of what it uses for their next day study	The SDT revised the definition of Operating Planning Analysis and Requirement R1. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed TOP-002-3, Requirement R1**:

Standard	Source	Language	Resolution
			Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
TOP-003-0	FERC Order 693	1620. …direct the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these type of issues. This new standard takes into account the recommendations from the Independent Expert Review Panel and SW Outage Report and brings all of the various outage coordination issues into one cohesive standard.
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of Project 2007-03 in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any

Standard	Source	Language	Resolution
			attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. In response to concerns raised by the IERP and the SW Outage Report, the SDT has developed proposed IRO-017-1 Outage Coordination. This standard requires the development of a coordinated outage process between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. If so desired, a Reliability Coordinator could include lead times in its process. In addition, proposed IRO-010-2 and TOP-003-2 dealing with data specifications could also cover this issue. The data specification must include any and all data required by the Reliability Coordinator, Transmission Operator and Balancing Authority. Planned outage data and timings could be included in such a data specification. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	Order 693	1622. Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these types of issues.

Standard	Source	Language	Resolution
TOP-003-0	Order 693	1624. Direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and part 1.1**: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and

Standard	Source	Language	Resolution
			external network data as deemed necessary by the Transmission Operator.
TOP-003-2	IERP	Requirements R1 and R2 do not address level of accuracy required; see if this is provided elsewhere (i.e. project 2009-02) Consolidate R1 and R2 at minimum; at max consolidate with RC (IRO-010-1a R1)	Level of accuracy is one of the issues identified in the Real-Time Tools Best Practices Task Force Report. NERC is currently instituting a review of all of the recommendations in various reports, including the Real-time Tools Best Practices Task Force report, to see what actions should be taken, if any are still required, to address recommendations in the reports. The SDT does not want to consolidate the two responsibilities. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Consolidate R3 and R4 at minimum; at max consolidate with RC (IRO-010-1a R2)	The SDT does not want to consolidate the two requirements or the two standards. The SDT feels Requirements R3 and R4 are for different tasks. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Requirement R5 should be consolidated with IRO-010-1a R3	The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	The SDT believes that this issue has been addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment,

Standard	Source	Language	Resolution
			and the requirement for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances. The SDT has developed a white paper on the topic of SOL exceedance to explain the technical rationale behind this resolution. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages,

Standard	Source	Language	Resolution
			generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R13**: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14**: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
TOP-004-1	Order 693	1637. …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Completed and filed in Oct 2008.

Standard	Source	Language	Resolution
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (… the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under … high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	The SDT feels that approvedEOP-001-2.1b dealing with emergency operations planning covers the intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, approved FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.
TOP-004-1	Order 693	1639. Consider Santa Clara's comment in the SDT process. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include	The data specification standards require that entities obtain all of the data that they need to perform their reliability functions. This would include frequency.

Standard	Source	Language	Resolution
		frequency monitoring in addition to the monitoring of voltage, real and reactive power flows	**Proposed IRO-010-2, Requirement R1**: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R1**: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	The SDT has clarified the issue. **Proposed TOP-001-3, Requirement R12:** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_{V}.
TOP-005	Order 693	1648. ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1.	The SDT has added specific parts to the data specification standards as well as revising the definitions of Operational Planning Analysis and Real-time Assessment to address this issue. **Proposed: Operational Planning Analysis -**An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation;

Standard	Source	Language	Resolution
			Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed IRO-010-2, Requirement r1, part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, requirement R1, part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-005	Order 693	1650. Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-3.

Standard	Source	Language	Resolution
		FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. ISO-NE recommends that the reference to "purchasing-selling entity" should be replaced with LSE.	Requirement R4 has been superseded by proposed TOP-003-3 which does include the indicated entities and has deleted PSE. **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
TOP-005	Order 693	1651. … deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.	The SDT believes that confidentiality is a market issue and not a reliability issue and as such it does not belong in the Reliability Standards. However, security of information is a reliability concern and the SDT has addressed that issue through the addition of requirements for establishing security protocols in data exchanges. **Proposed TOP-003-3, Requirement R5, part 5.3**: A mutually agreeable security protocol. **Proposed IRO-010-2, Requirement R3, part 3.3**: A mutually agreeable security protocol.
TOP-005	Order 693	1660. Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system	The SDT revised the definition of Real-time Assessment and Operations Planning Analysis to require Transmission Operators and Reliability Coordinators to ensure that those entities will have the capabilities they need to fulfill their reliability responsibilities.

Standard	Source	Language	Resolution
			Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)
TOP-006	Order 693	1665. Clarify the meaning of appropriate technical information concerning protective relays	That term is no longer used in the standards. To address concerns about the status of protection systems, the SDT has incorporated explicit references in the definitions of Operational Planning Analysis

Standard	Source	Language	Resolution
			and Real-time Assessment and the data specification standards. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed IRO-010-2, Requirement R1, part 1.2**:

Standard	Source	Language	Resolution
			Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, requirement R1, part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-006	Order 693	1664/1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	All requirements now have measures.
TOP-006	Order 693	1673. Direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan. NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and	Analysis is required in proposed TOP-002-3, Requirement R1 and in proposed TOP-001-3, Requirement R13. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1 and proposed TOP-001-3, Requirement R13 as shown in the revised definition of Operational Planning Analysis and Real-time Assessment. Additionally, approved NUC-001-2.1, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-3. Approved NUC-001-2, Requirements R3 & R8 cover the information flowing back to the nuclear plant operator.

Standard	Source	Language	Resolution
		Table 1 to account for the new requirement, and provides specific language to be included in those places.	**Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.) **Proposed TOP-002-3, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next

Standard	Source	Language	Resolution
			day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13**: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes. **Approved NUC-001-2.1, Requirement R3**: Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. **Approved NUC-001-2.1, Requirement R4.1**: Incorporate the NPIRs into their operating analyses of the electric system. **Approved NUC-001-2.1, Requirement R8:** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.
VAR-001-1	Order 693 Transferred from Project 2013-04	1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable	The approved definition of SOL includes voltage limits. The SDT has clarified the issue of having the Reliability Coordinator provide oversight.

Standard	Source	Language	Resolution
	Voltage and Reactive Control	entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	**Proposed IRO-002-4, Requirement4**: Each Reliability Coordinator shall monitor Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
INT-006-1	Order 693 Transferred from Project 2008-12 Coordinate Interchange Standards	866. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that makes it applicable to reliability coordinators and transmission operators. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission	An equally efficient and effective method of addressing the directive was approved by the Board and filed with FERC by Project 2008-12 SDT by including the term 'Interchange' in the definition of Operational Planning Analysis. This change has been retained by Project 2014-03. **Proposed IRO-008-2, Requirement R1** specifies that the Reliability Coordinator must perform an

Standard	Source	Language	Resolution
		operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. Then, in proposed IRO-008-2, Requirement R3, the Reliability Coordinator must develop a plan for addressing the problem. Then in proposed IRO-008-2, Requirement R4 the Reliability Coordinator notifies impacted entities. Similar requirements exist for the Transmission Operator in proposed TOP-002-3. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) **Proposed IRO-008-2, Requirement R1:** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) or

Standard	Source	Language	Resolution
			Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R3**: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R4:** Each Reliability Coordinator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R1:** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2:** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified

Standard	Source	Language	Resolution
			as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC Operating Committee Response to NERC Standards Committee / RISC Triage of IEPR Gaps

April 2, 2014

The NERC Operating Committee reviewed three perceived gaps, Outage Coordination, Governor Frequency Response, and Situational Awareness, as identified by the Independent Experts in their June 2013 report. As an important step in this review, the OC's Executive Committee met via WebEx with the Independent Experts to more thoroughly discuss and understand the thinking which led to these elements being cited as possible gaps. During the WebEx, the OCEC and the Independent Experts also reviewed all of the proposed requirements in the Independent Experts draft Authority matrix. The results of the OC's discussions, and the Project 2014-03 SDT's consideration within the revised TOP and IRO standards for two of the three perceived gaps (Outage Coordination and Situational Awareness) are presented below. The third gap identified by the Independent Experts, Governor Frequency Response, is outside the scope of Project 2014-03.

Outage Coordination

Draft requirements 3, 7, 8 and 9 of the Independent Experts draft Authority Standard focus on Outage Coordination. One concern recognized the fact that the Reliability Coordinators have a wide area view and broader situational awareness, allowing for early identification and resolution of conflicts. Therefore the RCs should have the most influence on outage coordination. Further concerns identify standards that are currently in flux, particularly those remanded standards in which requirements are being removed.

Operating Committee opinion

The Operating Committee concurs that Outage Coordination is an important grid reliability function. Outage coordination should originate from the TOPs and GOPs; with conflicts resolved by their respective RC. It makes sense for this process to begin with a set of previously approved scheduled long term outages with a sufficient time margin for results to be incorporated into seasonal operating studies. Further, the RC should retain the authority for final approval up to the time the asset is removed from service, as well as recall authority (if technically feasible and appropriate to recall) as needed to prevent or mitigate emergencies.

Longer term outage coordination is necessary for those assets that require long maintenance planning pursuant to the type of work required, such as turbine rebuilds, nuclear refueling, etc. This likely belongs in the scope of the Planning Coordinator (PC) for outages planned more than 12-months into the future. A Reliability Standard could be written that requires PCs to coordinate long term outages and which requires responsible entities (e.g., GOs, TOs) to request a time slot in which to perform whatever maintenance is required.

In either case, during the longer term planning horizon, or the Operations planning and real time operations time frame, each PC or RC should have an understanding of the impacts on neighboring PCs or RCs when those assets are planned to be out or are forced out, with notification/coordination requirements with these PCs or RCs.

SDT response:

To enhance reliability, the Project 2014-03 SDT has provided explicit requirement language to address the need for planned outage coordination at the Reliability Coordinator level. See proposed IRO-014-3, Requirement R1, part 1.4. The SDT has also added the Planning Coordinator and Transmission Planner to the applicability section of proposed IRO-010-2 to ensure that outage data is addressed. The Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address overall outage coordination issues.

Proposed IRO-014-3, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Situational Awareness (EMS RTCA models)

In this gap the Independent Experts recommend the development of a standard that defines the requirements for EMS RTCA models or performance expectations of the models (Project 2009-02 – Real Time Monitoring and Analyses Capabilities).

Operating Committee opinion

The Operating Committee has a concern that this gap could be interpreted as recommending a "HOW" standard where specific tools would be required even for the smallest TOPs, as opposed to a "WHAT" standard that would allow for other ways to accomplish the objective. In conversations with the Independent Experts it became clear that proper situational awareness was the primary concern. The OC concurs that real time contingency analysis process (real time updated topology and telemetry) should be performed on each BES facility. This functionality could be performed by use of an RTCA application at the TO or RC level, or coverage by alternate means would be appropriate.

SDT response:

The Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13. In addition, the Project 2014-03 SDT has revised the definition of Real-time Assessment to allow for contracting needed services to accommodate concerns for smaller entities.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall perform a Real-Time Assessment at least once every 30 minutes.

Remainder of the draft Authority Standard Requirements

Authority R1

Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.

Operating Committee opinion

The current IRO-001-1.1 and TOP-001-1a are expected to be retired and replaced by IRO-001-3. In either case, these standards contain the authority to act, but the requirement to act appears to be implicit. The OC agrees that the RC, TOP and BA should explicitly be required to act.

SDT response:

The Project 2014-03 SDT agrees and has adjusted the wording in the standards to address this issue.

Proposed IRO-001-4, Requirement R1: Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.

Proposed TOP-001-3, Requirement R1: Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area.

Proposed TOP-001-3, Requirement R2: Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.

Authority R2

Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.

Operating Committee opinion

The current IRO-002-2 provides for the RC to have control of its tools but does not include the TOP or BA. IRO-002-2 is expected to be retired and replaced by IRO-002-3, which clarifies that the system operators have the authority to approve outages of analysis tools (The OC suggests adding "under the direct control of their company"), but does not include TOPs or BAs. The OC concurs

with the clarification in IRO-002-3, and the OC further agrees that TOPs and BAs should be included.

SDT response:

The Project 2014-03 has added proposed TOP-001-3, Requirements R16 and R17 to provide Transmission Operators and Balancing Authorities with capabilities similar to those of the Reliability Coordinator.

> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own monitoring and Real-time Assessment capabilities.
>
> Proposed TOP-001-3, Requirement R17: Each Balancing Authority shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities.

Authority R4

RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.

Operating Committee opinion

During the OCEC/Independent Expert webex, the Independent Experts explained that the objective of this requirement is to mandate the posting of a letter in the control rooms granting authority to the system operators to carry out their required tasks. While the Operating Committee believes this is a good practice, it does not believe that it rises to the level of a Standards Requirement.

SDT response:

The Project 2014-03 SDT agrees with the position of the Operating Committee Executive Committee. A letter of authority located in the Control Room is an example of good utility practice. A change to the requirements is not warranted.

Authority R5

Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

In relation to R1 above this understanding seems implicit. However, in the interest of clarity the OC would support this requirement.

SDT response:

The Project 2014-03 SDT agrees.

> Proposed TOP-001-3, Requirement R3: Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.
>
> Proposed TOP-001-3, Requirement R5: Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.
>
> Proposed IRO-001-4, Requirement R2: Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Authority R6

Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

IRO-014-5, IRO-015-1 and IRO-016-1 describe inter RC procedures, Plans, notifications and coordination. These standards are expected to be retired and replaced by IRO-014-2 incorporating the pertinent requirements from the retiring standards. However, none of these standards explicitly include a requirement for one RC to comply with a directive from another RC.

The OC recognizes that coordination between RCs is vitally important. It is also recognized that an RC is the entity with the best understanding and situational awareness of its unique footprint. Therefore it is not believed to be beneficial for operational reliability for one RC to direct the actions of another RC. Rather, it is more appropriate to have this type of coordination documented within the requisite Joint Operating Agreements in which the appropriate assistance would be documented and understood in advance of such actions.

SDT response:

The Project 2014-03 SDT believes that proposed IRO-014-2 Requirements R5 – R8 already require Reliability Coordinators to coordinate and implement action plans even if the RC cannot agree that a problem exists or what the exact action plan is

> Proposed IRO-014-2, Requirement R5: Each Reliability Coordinator, upon identification of an Emergency, shall notify other impacted Reliability Coordinators.
>
> Proposed IRO-014-2, Requirement R6: Each impacted Reliability Coordinator shall operate as though the problem exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R7: Each Reliability Coordinator that identified an Emergency shall develop an action plan to resolve the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R8: Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **July 2, 2014**.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

The project web page can be found at: http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx

Background Information - Project 2014-03 – Revisions to TOP/IRO Reliability Standards

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards.

On November 21, 2013, FERC issued a NOPR proposing to remand three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards and four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards. In the NOPR, FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."

In response, NERC filed a motion requesting that FERC defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process. That motion to defer action was granted on January 14, 2014.

The drafting team formed to address those concerns has made revisions to the TOP and IRO standards proposed to be remanded, along with several other IRO standards to provide consistency amongst the TOP and IRO standards, to address NOPR issues and recommendations made by the Independent Expert Review Panel, the IRO five-year review team, and the 2011 SW Outage Report.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

The SDT requests that commenters not use these comments as a forum for questioning the issues raised in the FERC NOPR of November 21, 2013, but to objectively evaluate the work of the SDT in responding to the issues raised in the NOPR, and the recommendations made by the Independent Expert Review Panel (IERP), the IRO FYRT, and the SW Outage Report.

Questions

1. Do you agree with the changes made to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the changes made to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you agree with the changes made to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

4. Do you agree with the changes made to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

5. Do you agree with the changes made to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

6. The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

7. Do you agree with the changes made to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

8. Do you agree with the changes made to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

9. Do you agree with the changes made to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

Comments:

10. The mapping document posted on the project page explains how the drafting team believes Requirements from 5 IRO standards that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards IRO-003-2, IRO-004-2, IRO-005-3.1a, IRO-015-1, and IRO-016-1? If not, why not? Please be specific.

    Yes:

    No:

    Comments:

11. The mapping document posted on the project page explains how the drafting team believes Requirements from 5 TOP standards and 1 PER standard that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards TOP-004-2, TOP-005-2a, TOP-006-3, TOP-007-0, TOP-008-1, and PER-001-0? If not, why not? Please be specific.

    Yes:

    No:

    Comments:

12. The SDT is seeking input on whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators. Please explain what you feel the correct periodicity and supply technical rationale for your suggestion.

    Comments:

13. Do you have any comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.

    Yes:

    No:

    Comments:

14. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not

agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

Yes:

No:

Comments:

15. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

Yes:

No:

Comments:

Standards Announcement Reminder

Project 2014-03 Revisions to TOP and IRO Standards

Ballots and Non-Binding Polls Now Open through July 2, 2014

Now Available

Ballots for the **TOP/IRO Reliability Standards**, definitions, and implementation plan; and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Wednesday, July 2, 2014.**

If you have questions please contact Ed Dobrowolski via email or by telephone at (609) 947-3673.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards, implementation plan, definitions and non-binding polls of the associated VRFs and VSLs by clicking here.

Please note that there are a total of 20 ballots open for this project, as follows:

Ballots and Non-binding polls for Nine Standards (total of 18 ballots):

- IRO-001-4 – ballot and non-binding poll
- IRO-002-4 – ballot and non-binding poll
- IRO-008-2 – ballot and non-binding poll
- IRO-010-2 – ballot and non-binding poll
- IRO-014-3 – ballot and non-binding poll
- IRO-017-1 – ballot and non-binding poll
- TOP-001-3 – ballot and non-binding poll
- TOP-002-4 – ballot and non-binding poll
- TOP-003-2 – ballot and non-binding poll

Two Ballots of Implementation plan and definitions:

- Project 2014-03 Implementation Plan – ballot
- Project 2014-03 Definitions – ballot

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Formal Comment Period Now Open through July 2, 2014
Ballot Pools Forming Now through June 17, 2014

Upcoming:
Ballots and Non-Binding Polls: June 23 – July 2, 2014

Now Available

A 45-day formal comment period for the **TOP/IRO Reliability Standards** is open through **8 p.m. Eastern on Wednesday, July 2, 2014.** The join ballot pool windows are currently open through **8 p.m. Eastern on Tuesday, June 17, 2014.**

If you have questions please contact Ed Dobrowolski via email or by telephone at (609) 947-3673.

Background information for this project can be found on the project page.

Instructions for Commenting
Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pool
Two ballots pools are being formed for Project 2014-03 – one for the TOP and IRO Reliability Standards and one for the associated non-binding polls on this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submittal of an opinion for the non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot: bp-2014-03 TOP/IRO_STDS_in@nerc.com
Non-Binding Poll: bp-2014-03 TOP/IRO_NB_in@nerc.com

Next Steps
Ballots for the standards and non-binding polls of the associated VRFs and VSLs will be conducted **June 23 – July 2, 2014.**

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual].

For more information or assistance, please contact [Wendy Muller],
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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Formal Comment Period Now Open through July 2, 2014
Ballot Pools Forming Now through June 17, 2014

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Non-Binding Poll: bp-2014-03 TOP/IRO_NB_in@nerc.com

Next Steps

Ballots for the standards and non-binding polls of the associated VRFs and VSLs will be conducted **June 23 – July 2, 2014.**

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Ballot and Non-Binding Poll Results

Now Available

Ballots for nine **TOP/IRO Reliability Standards**, two definitions, and the implementation plan; and nine non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, July 2, 2014**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results	Non-Binding Poll Results
	Quorum /Approval	Quorum/Supportive Opinions
IRO-001-4	82.32% / 68.57%	82.11% / 55.56%
IRO-002-4	82.59% / 36.94%	81.52% / 39.46%
IRO-008-2	82.59% / 47.87%	82.11% / 47.09%
IRO-010-2	82.85% / 60.26%	82.11% / 55.14%
IRO-014-3	82.85% / 61.67%	82.11% / 52.41%
IRO-017-1	82.06% / 57.94%	81.52% / 56.99%
TOP-001-3	82.59% / 30.99%	81.82% / 33.49%
TOP-002-4	82.85% / 62.18%	82.11% / 55.78%
TOP-003-3	82.85% / 63.07%	82.40% / 54.42%
2 Definitions	81.00% / 62.64%	N/A
Implementation Plan	80.74% / 64.70%	N/A

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-03 TOP-001-3
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	313
Total Ballot Pool:	379
Quorum:	82.59 % The Quorum has been reached
Weighted Segment Vote:	30.99 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	20	0.263	56	0.737	0	4	25
2 - Segment 2	9	0.7	1	0.1	6	0.6	0	2	0
3 - Segment 3	83	1	23	0.343	44	0.657	0	7	9
4 - Segment 4	30	1	10	0.455	12	0.545	0	1	7
5 - Segment 5	82	1	21	0.333	42	0.667	0	5	14
6 - Segment 6	52	1	19	0.413	27	0.587	0	0	6
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	1	0.1	3	0.3	0	0	1
9 - Segment 9	3	0.2	0	0	2	0.2	0	0	1

10 - Segment 10	8	0.5	1	0.1	4	0.4	0	2	1
Totals	**379**	**6.8**	**96**	**2.107**	**196**	**4.693**	**0**	**21**	**66**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	

1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support NPCC RSC comment (requires TOPs to monitor facilities in neighboring TOP areas, overlaps RC))
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)

1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Negative)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	COMMENT RECEIVED
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committe

				(Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon - Exelon)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Negative	COMMENT RECEIVED
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
				SUPPORTS THIRD

3	Nebraska Public Power District	Tony Eddleman	Negative	PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	COMMENT RECEIVED
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Chris Scanlon)
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
				SUPPORTS THIRD

5	Lincoln Electric System	Dennis Florom	Negative	PARTY COMMENTS - (MRO NRSF)
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Regional Standards Committee comments)
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)

5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren Comments)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon Exelon)
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	COMMENT RECEIVED
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(David Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro's Patricia Robertson)
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comment in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)

9	New York State Public Service Commission	Diane J Barney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF re: this Standard)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 TOP-002-4
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	314
Total Ballot Pool:	379
Quorum:	**82.85 % The Quorum has been reached**
Weighted Segment Vote:	62.18 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	40	0.548	33	0.452	0	8	24
2 - Segment 2	9	0.7	3	0.3	4	0.4	0	2	0
3 - Segment 3	83	1	36	0.571	27	0.429	0	11	9
4 - Segment 4	30	1	11	0.611	7	0.389	0	5	7
5 - Segment 5	82	1	35	0.593	24	0.407	0	9	14
6 - Segment 6	52	1	28	0.667	14	0.333	0	4	6
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**6.9**	**163**	**4.29**	**111**	**2.61**	**0**	**40**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		

1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	

1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRc and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	

3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		

4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	

5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		

5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	

6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comment in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 TOP-003-3
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	314
Total Ballot Pool:	379
Quorum:	**82.85 % The Quorum has been reached**
Weighted Segment Vote:	63.07 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative				
			# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	38	0.521	35	0.479	0	7	25
2 - Segment 2	9	0.7	5	0.5	2	0.2	0	2	0
3 - Segment 3	83	1	34	0.523	31	0.477	0	9	9
4 - Segment 4	30	1	14	0.667	7	0.333	0	2	7
5 - Segment 5	82	1	34	0.548	28	0.452	0	6	14
6 - Segment 6	52	1	29	0.63	17	0.37	0	1	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals	**379**	**6.8**	**163**	**4.289**	**122**	**2.511**	**0**	**29**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	NO COMMENT RECEIVED

1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		

1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	

3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	

3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Negative	COMMENT RECEIVED
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		

5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	

5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
				SUPPORTS THIRD

6	Con Edison Company of New York	David Balban	Negative	PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED

6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-001-4
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	312
Total Ballot Pool:	379
Quorum:	82.32 % The Quorum has been reached
Weighted Segment Vote:	68.57 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	45	0.625	27	0.375	0	8	25
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	1	0
3 - Segment 3	83	1	39	0.609	25	0.391	0	10	9
4 - Segment 4	30	1	13	0.565	10	0.435	0	0	7
5 - Segment 5	82	1	36	0.621	22	0.379	0	8	16
6 - Segment 6	52	1	32	0.711	13	0.289	0	2	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals	**379**	**6.9**	**181**	**4.731**	**100**	**2.169**	**0**	**31**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Sandifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	

1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
				SUPPORTS THIRD

1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	COMMENT RECEIVED
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	

3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Coop)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)

3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA

				and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	COMMENT RECEIVED
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	

5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NRSF)
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	

5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro (Patricia Robertson))
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Ballot Results	
Ballot Name:	Project 2014-03 IRO-002-4
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	313
Total Ballot Pool:	379
Quorum:	**82.59 % The Quorum has been reached**
Weighted Segment Vote:	36.94 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative				No Vote
			# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	
1 - Segment 1	105	1	24	0.364	42	0.636	0	15	24
2 - Segment 2	9	0.7	0	0	7	0.7	0	2	0
3 - Segment 3	83	1	20	0.37	34	0.63	0	18	11
4 - Segment 4	30	1	7	0.412	10	0.588	0	6	7
5 - Segment 5	82	1	24	0.462	28	0.538	0	16	14
6 - Segment 6	52	1	20	0.541	17	0.459	0	10	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	0	0	2	0.2	0	0	1

10 - Segment 10	8	0.6	1	0.1	5	0.5	0	1	1
Totals	**379**	**6.9**	**99**	**2.549**	**146**	**4.351**	**0**	**68**	**66**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative,	Bob Solomon		

	Inc.			
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC (R1 redundant with COM-001-2))
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))

1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support PJM comments)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	NO COMMENT RECEIVED
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT

				RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC-SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative Inc)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC comments)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Commitee)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	

3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM and Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	NO COMMENT RECEIVED
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	

5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	

6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
9	New York State Public Service Commission	Diane J Barney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF re this standard)
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC review group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-008-2
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	313
Total Ballot Pool:	379
Quorum:	82.59 % The Quorum has been reached
Weighted Segment Vote:	47.87 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	29	0.468	33	0.532	0	19	24
2 - Segment 2	9	0.7	1	0.1	6	0.6	0	2	0
3 - Segment 3	83	1	23	0.434	30	0.566	0	20	10
4 - Segment 4	30	1	7	0.438	9	0.563	0	7	7
5 - Segment 5	82	1	24	0.48	26	0.52	0	17	15
6 - Segment 6	52	1	21	0.583	15	0.417	0	11	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	3	0.3	3	0.3	0	1	1
Totals	**379**	**6.9**	**113**	**3.303**	**123**	**3.598**	**0**	**77**	**66**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	

1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support PJM comments)

1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC-SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Abstain	

3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	

3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM and Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	

5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	

6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)

6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Ballot Results	
Ballot Name:	Project 2014-03 IRO-010-2
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	314
Total Ballot Pool:	379
Quorum:	**82.85 % The Quorum has been reached**
Weighted Segment Vote:	60.26 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	43	0.581	31	0.419	0	7	24
2 - Segment 2	9	0.8	3	0.3	5	0.5	0	1	0
3 - Segment 3	83	1	37	0.569	28	0.431	0	9	9
4 - Segment 4	30	1	13	0.591	9	0.409	0	1	7
5 - Segment 5	82	1	33	0.55	27	0.45	0	7	15
6 - Segment 6	52	1	30	0.667	15	0.333	0	2	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals	**379**	**6.9**	**168**	**4.158**	**117**	**2.742**	**0**	**29**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		

1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	COMMENT RECEIVED
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		

3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

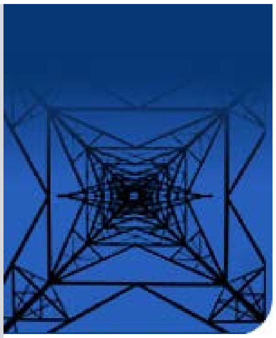
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	COMMENT RECEIVED
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		

5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
				SUPPORTS THIRD

5	Omaha Public Power District	Mahmood Z. Safi	Negative	PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro's Patricia Robertson)
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in "Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx")
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		



10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-014-3
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	314
Total Ballot Pool:	379
Quorum:	82.85 % The Quorum has been reached
Weighted Segment Vote:	61.67 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	35	0.556	28	0.444	0	18	24
2 - Segment 2	9	0.7	4	0.4	3	0.3	0	2	0
3 - Segment 3	83	1	30	0.545	25	0.455	0	19	9
4 - Segment 4	30	1	10	0.625	6	0.375	0	7	7
5 - Segment 5	82	1	29	0.58	21	0.42	0	17	15
6 - Segment 6	52	1	24	0.649	13	0.351	0	10	5
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	4	0.4	2	0.2	0	1	1
Totals	**379**	**6.9**	**141**	**4.255**	**99**	**2.645**	**0**	**74**	**65**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	

1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	

1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC-SRC)
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	

3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
				SUPPORTS THIRD

3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Commitee)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	

4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)

5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	

5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Ballot Results	
Ballot Name:	Project 2014-03 IRO-017-1
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	311
Total Ballot Pool:	379
Quorum:	82.06 % The Quorum has been reached
Weighted Segment Vote:	57.94 %
Ballot Results:	The ballot has closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	41	0.569	31	0.431	0	8	25
2 - Segment 2	9	0.7	1	0.1	6	0.6	0	2	0
3 - Segment 3	83	1	36	0.581	26	0.419	0	12	9
4 - Segment 4	30	1	10	0.526	9	0.474	0	4	7
5 - Segment 5	82	1	28	0.483	30	0.517	0	8	16
6 - Segment 6	52	1	25	0.581	18	0.419	0	3	6
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.5	5	0.5	0	0	0	2	1
Totals	**379**	**6.8**	**152**	**3.94**	**120**	**2.86**	**0**	**39**	**68**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative,	Bob Solomon		

	Inc.			
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ayesha Sabouba)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
				SUPPORTS THIRD

1	Salt River Project	Robert Kondziolka	Negative	PARTY COMMENTS - (Salt River Project)
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Amy Casuscelli, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	COMMENT RECEIVED
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC and NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	

3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	

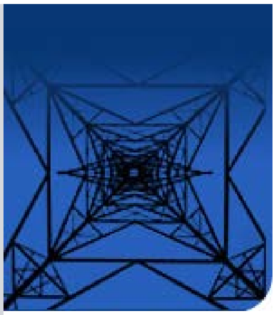
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee(Member Services))
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
				SUPPORTS THIRD

4	Georgia System Operations Corporation	Guy Andrews	Negative	PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	COMMENT RECEIVED
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
				SUPPORTS THIRD

5	Dominion Resources, Inc.	Mike Garton	Negative	PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		

5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro's Patricia Robertson)
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Negative	COMMENT RECEIVED
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		



10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2014-03 Definitions
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	307
Total Ballot Pool:	379
Quorum:	**81.00 % The Quorum has been reached**
Weighted Segment Vote:	62.64 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	36	0.529	32	0.471	0	10	27
2 - Segment 2	9	0.3	2	0.2	1	0.1	0	5	1
3 - Segment 3	83	1	32	0.552	26	0.448	0	15	10
4 - Segment 4	30	1	9	0.529	8	0.471	0	6	7
5 - Segment 5	82	1	29	0.537	25	0.463	0	12	16
6 - Segment 6	52	1	25	0.625	15	0.375	0	6	6
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**6.5**	**144**	**4.072**	**108**	**2.428**	**0**	**55**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
				SUPPORTS

1	Gainesville Regional Utilities	Richard Bachmeier	Negative	THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (David

				Austin)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		

1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	

3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP

				Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		

4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)

5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Nevada Power Co.	Richard Salgo	Abstain	

5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 TOP/IRO Implementation Plan
Ballot Period:	6/23/2014 - 7/2/2014
Ballot Type:	Initial
Total # Votes:	306
Total Ballot Pool:	379
Quorum:	**80.74 % The Quorum has been reached**
Weighted Segment Vote:	64.70 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	33	0.524	30	0.476	0	15	27
2 - Segment 2	9	0.3	2	0.2	1	0.1	0	5	1
3 - Segment 3	83	1	34	0.586	24	0.414	0	15	10
4 - Segment 4	30	1	10	0.625	6	0.375	0	7	7
5 - Segment 5	82	1	30	0.577	22	0.423	0	14	16
6 - Segment 6	52	1	22	0.564	17	0.436	0	7	6
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.3	3	0.3	0	0	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.5	5	0.5	0	0	0	2	1
Totals	**379**	**6.3**	**141**	**4.076**	**100**	**2.224**	**0**	**65**	**73**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
				COMMENT

1	Georgia Transmission Corporation	Jason Snodgrass	Negative	RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs utility)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
				SUPPORTS THIRD PARTY COMMENTS -

1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	(SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	

2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
				SUPPORTS

3	Florida Power Corporation	Lee Schuster	Negative	THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	

3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
				SUPPORTS THIRD PARTY

5	Great River Energy	Preston L Walsh	Negative	COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	

5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT

				RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	
				SUPPORTS THIRD PARTY COMMENTS - (See comments in

6	Tampa Electric Co.	Benjamin F Smith II	Negative	"Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx")
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		Roger C Zaklukiewicz		
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_TOP-001-3
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	279
Total Ballot Pool:	341
Summary Results:	81.82% of those who registered to participate provided an opinion or an abstention; 33.49% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi		
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC (R10 TOPs

				monitor facilaties in neighbouring TOP areas overlaps RC area))
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)

3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (thomas Standifur)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	

4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		

5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED

5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utility)
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)

5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		

5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Colorado Springs Utility)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc.

				Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in "Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx")
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF re:this standard)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	

10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_TOP-002-4
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	280
Total Ballot Pool:	341
Summary Results:	82.11% of those who registered to participate provided an opinion or an abstention; 55.78% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal

NERC

				Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	

1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))

3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		

3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	

3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	

4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	

5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	

6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See

				comments in "Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx")
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_TOP-003-3
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	281
Total Ballot Pool:	341
Summary Results:	82.40% of those who registered to participate provided an opinion or an abstention; 54.42% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACEs and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	

1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	

1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood) Safi)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	

3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	

3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD

				PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Negative	COMMENT RECEIVED
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD

				PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	

5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	

5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	

5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	

5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	

6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc.

				Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-001-4
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	278
Total Ballot Pool:	341
Summary Results:	82.11% of those who registered to participate provided an opinion or an abstention; 55.56% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NRSF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS -

NERC

				(FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	

1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		

3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	

3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		

4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	

5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	

5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Two Ballots of Implementation plan and definitions:)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole

				Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-002-4
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	278
Total Ballot Pool:	341
Summary Results:	82.52% of those who registered to participate provided an opinion or an abstention; 39.46% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC (R1 redundant with COM-001-2))
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	

1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)

1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)

3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)

3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)

3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)

3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric

				Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)

5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Regional Standards Committee comments)
5	NextEra Energy	Allen D Schriver		

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		

5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Abstain	

6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

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Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-008-2
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	280
Total Ballot Pool:	341
Summary Results:	82.11% of those who registered to participate provided an opinion or an abstention; 47.09% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)

1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Abstain	

1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SERC OC)
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		

3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)

3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)

5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards

				Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corp Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)

6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	

8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group comments)
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-010-2
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	280
Total Ballot Pool:	341
Summary Results:	82.11% of those who registered to participate provided an opinion or an abstention; 55.14% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))

1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	

1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC

				Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY

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				COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charles Rogers)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	

4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA and FRCC MS OC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		

5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Charlie Rogers)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED

5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	

5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)

6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)

6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-014-3
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	280
Total Ballot Pool:	341
Summary Results:	82.11 of those who registered to participate provided an opinion or an abstention; 52.41% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	

1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		

1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)

1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		

1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sputhern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	

4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	

5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support AECI's comments)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-017-1
Poll Period:	6/23/2014 - 7/2/2014
Total # Opinions:	278
Total Ballot Pool:	341
Summary Results:	81.52% of those who registered to participate provided an opinion or an abstention; 56.99% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ayesha Sabouba)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Salt River Project)
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED

2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		

3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & FRCC)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards

				Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	

4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC submitted by Scott McGough)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	SUPPORTS THIRD PARTY COMMENTS - (BPA's comments)

5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC Georgia System Operations Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	

5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz, FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)

6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Group)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc. Corporate Compliance)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments in “Project 2014-03_TOP-IRO SDT_FRCC MS OC Comment Form.docx”)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	

10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (71 Responses)
Name (48 Responses)
Organization (48 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Question 1 (52 Responses)
Question 1 Comments (63 Responses)
Question 2 (45 Responses)
Question 2 Comments (63 Responses)
Question 3 (42 Responses)
Question 3 Comments (63 Responses)
Question 4 (53 Responses)
Question 4 Comments (63 Responses)
Question 5 (43 Responses)
Question 5 Comments (63 Responses)
Question 6 (54 Responses)
Question 6 Comments (63 Responses)
Question 7 (59 Responses)
Question 7 Comments (63 Responses)
Question 8 (55 Responses)
Question 8 Comments (63 Responses)
Question 9 (56 Responses)
Question 9 Comments (63 Responses)
Question 10 (44 Responses)
Question 10 Comments (63 Responses)
Question 11 (47 Responses)
Question 11 Comments (63 Responses)
Question 12 (24 Responses)
Question 12 Comments (63 Responses)
Question 13 (39 Responses)
Question 13 Comments (63 Responses)
Question 14 (32 Responses)
Question 14 Comments (63 Responses)
Question 15 (47 Responses)
Question 15 Comments (63 Responses)

Individual
Scott McGough
Georgia System Operations
Yes
No
GSOC believes Requirements 1 and 2 are redundant with existing effective COM-001-1 R1 and future mapping of this requirement to future enforceable standards. COM-002-2 R1 is the corresponding requirement for the TOPs and BAs to have both voice and data links with appropriate RCs, BAs, and TOPs. GSOC suggests that these existing standards and other industry approved future enforceable standards addresses any reliability gaps. R2 is redundant with both the existing and proposed IRO-010 in this project. IRO-010 already requires the RC to provide data specifications to the entities listed in R2 and requires such entities to provide the data specified by the RC. GSOC recommends that both R1 and R2 be removed. As an alternative to removing R2, TPs/PCs may be removed from R2 because these functional entities were specifically added to IRO-010 for purposes of providing UFLS and UVLS data to RCs. They do not need to be in both standards. The proposed Requirement 3 needs to be revised to clarify that it is only addressing monitoring and analysis capabilities and not planned outages and maintenance of BES elements. As currently drafted, one could interpret it as planned outages of BES element and maintenance of monitoring and analysis capabilities.

GSOC suggest changing the requirement to, “Each Reliability Coordinator shall provide its System Operators with the authority to approve the following: R3.1. planned outages of its monitoring and analysis capabilities. R3.2. maintenance of its monitoring and analysis capabilities. Requirement 4, as proposed, does not indicate how far into the neighboring system a RC should monitor. GSOC agrees with its RC to suggest incorporating language referencing the RCs wide area view methodology and language specifying that it should include sub-100 kV facilities, “as deemed necessary by the RC” (similar to the language used in the proposed IRO-010-2 R1.1). Please consider the following to add clarity to the requirement: “Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas consistent with its wide-area view methodology to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area , including sub-100 kV facilities, as deemed necessary by the Reliability Coordinator, and the status of Special Protection Systems, to make this determination. “
No
: By the various uses of “Operating Plan” in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? GSOC agrees with its RC that IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded. It will require RCs to produce an email response to all TOP and BA operating plans stating “reviewed”. RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, making R2 unnecessary.
Yes
Yes
No
GSOC agrees with its RC that this standard is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary, which is current day and next day operations. As written, this requirement conflicts with the Functional Model and the NERC Glossary, which both clearly address the roles of the Reliability Coordinator. The Reliability Coordinator, according to the Functional Model, “receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.” Furthermore, the NERC Glossary notes that the Reliability Coordinator “is to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.” This definition indicates that the Reliability Coordinator’s scope is for next day and real-time operations. GSOC recommends that this standard be withdrawn from the project. If the SDT does not withdraw the standard, at a minimum, the SDT should modify the standard to address the following comments. The proposed subpart 1.5 requires RCs to document and maintain the specifications for outage analysis during the operations planning horizon, which is next day to one year out. GSOC recommends adding language to subpart 1.5 to clearly state that the RC has discretion by adding “, if deemed necessary by the RC” to the end. GSOC does not agree with R4 as it seems to imply that RCs conduct outage coordination assessments even beyond the operations planning horizon. Again, RCs are focused on real time and next day timeframes, not the Planning Assessment timeframe, and should not be required to coordinate solutions in the Planning Assessment timeframe. This requirement is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary (see definition of RC), which is current day and next day operations. This requirement should be removed, or, at a minimum, be revised to include “if deemed necessary by the RC”. The existing TOP-002-2.1b R11 requires TOPs to perform seasonal studies to determine SOLs and to provide the results of those studies to its RC.
No
R1 and R2 – Request that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 – The Rationale section for Requirement R7 states that the word ‘Emergency’ was deleted and the word ‘Effective’ was added to the Requirement language. The word ‘Effective’ is missing from the Requirement language. Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, we believe the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other Standards closely associated such as COM-002-4. We recommend replacing the terms “reliability of the Interconnection” with the terms “reliability of the Bulk Electric System (BES)”. The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment “affecting the reliability of the BES” is not very routine. The intent of this requirement should be for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. The use of the NERC term “Emergency” would capture this intent. We propose the language “[during an Emergency]” be added after “….shall comply with each Operating Instruction issued by its Transmission Operator(s) [ ] ”. R8 – We suggest that the phrase ‘could result in’ is too open ended and assumes that operations takes place as expected and does not account for failures and equipment during the operations such as faulted breaker, or human performance errors. R9 – Add the word ‘planned’ to Requirement language to match Measure language. R9 – The phrase ‘negatively impacted Interconnected NERC

registered entities' seems broadly generic. GSOC suggests adding the words, 'other affected adjacent BAs and TOPs'. R16 and R17 – These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 – These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 – There is confusion in the Industry of what the current term 'derived limits' means. The SDT should take this opportunity to clarify whether 'derived limits' is referring to SOLs, IROLs. If this is the case, then why use the term, 'derived limits'?
No
: GSOC agrees with its RC that sub requirements, 4.1, 4.2, 4.3 and 4.4 are vague in nature and should be more descriptive by defining specific expectations of what should be addressed. Example: R4.2 as written is unclear as to whether the BAs Operating Plan is expected to address making, accommodating, curtailing, ramping of interchange schedules, etc. R4 and R5 and R7 – It is unclear on what actions would be included in the BA Operating Plan. In the case of the TOP, it is very clear in that the Operating Plan is to address potential SOLs. The R4 subparts include data provided to the BA for reserves planning purposes from other entities. The BA should not be required to notify all entities and provide them with the very information those entities provided to the BA as seems to be required in R5. R6 and R7 – GSOC suggest that a periodicity for providing data and a deadline by which the respondent is to provide the indicated data should be applied to these requirements to be consistent with corresponding RC requirements, R1.3 and R1.4 in proposed IRO-010-2 Reliability Coordinator Data Specification and Collection.
Yes
Yes
Yes
No
No
The bandwidth between "lower" and "severe" VSL is only 15 minutes. Expand bandwidth.
No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
No
Yes
Yes
Although PacifiCorp supports the elimination of duplicate language in these Standards, much of the new language in the revised Standards is diluted and is more vague as a result.
Group
Norteast Power Coordinating Council
Guy Zito
No
To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). An Operating Instruction applies to both Normal and Emergency operations. Therefore, the VSL should be graduated similar to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is a Moderate VSL.
No
To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). Requirements R1 and R2 appear redundant to the COM-001 Standard; suggest these requirements be deleted. R1 requires voice communication as opposed to the COM-001-2 requirement for the RC to utilize Interpersonal Communication, which is defined as “Any medium that allows two or more individuals to interact, consult, or exchange information.” Is a RC supposed to have voice communication and Interpersonal Communication, or does voice communication apply to both IRO-002 and COM-001? If this is the case, then these two requirements are redundant. R2 requires data links while the VSL utilizes data link facilities. We prefer the use of data link facilities. The use of facilities would imply that this is not a SCADA point by point requirement but an overall emplacement of equipment required to transmit data. It also helps address the concern that the requirement as written implies the data link is operational 24/7. The NERC Event Analysis Program has issued lessons learned where data communications between entities have been interrupted due to EMS issues. Finally, it would avoid any redundancy with the proposed IRO-010 R3 or IRO-014 R3. R3- System Operators should have authority to both approve and disapprove planned outages. From R3, “…maintenance of its monitoring and analysis capabilities.” What is “its” referring to? The Rationale isn’t clear on this either. R4- Suggest rephrasing R4 because the last phrase starting with word “including” is modifying the Facilities being monitored and not the type of exceedances being monitored for. Reword to “Each Reliability Coordinator shall monitor facilities, including sub-100 kV facilities when necessary and the status of Special Protection Systems in its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.” R5 contains some ‘how, not why’ language: “giving particular emphasis to alarm management and awareness systems, automated data transfers,” which may, in fact, produce a lowest common denominator approach to EMS systems. A part of the Requirement is also redundant to COM-001: “over a redundant and highly reliable infrastructure.” R5 could be improved to become performance oriented by removing ambiguous terms. For example, what is the measure of particular emphasis, and highly reliable? Also, does redundancy mean to have a Primary and Backup in which case EOP-008 already requires this redundancy? We suggest rephrasing to: Each Reliability Coordinator shall have systems that provide Real-time situational awareness of the BES to its System Operators.
No
Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, but the standard refers to a revised definition of "Operational Planning Analysis". Suggest keeping the Purpose of IRO-008-1. The proposed Purpose in IRO-008-2 does not adequately introduce what the performed analyses and assessments are performed on.
No
Similar to TOP-003, R1 and R2 VRFs should be Low, not Medium.
No
In Measure M1, for consistency remove the "s" from "notifications" so that the language matches that of R1, or add an a "s" to "notification" in R1. To be consistent with other approved standards, add an "s" to "compliance audit", self-

certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Requirements R2 and R4, as well as R1 sub-Part 1.1, indicate “and the process to follow in making those notifications.” Drafting Teams should focus on developing results-based standards.
No
The Purpose needs to be revised to indicate that the outages are properly coordinated between whom? To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
No
Requirement R5 has a zero-defect problem similar to what was argued for COM-002-4. A single instance of a failure to comply with any Operating Instruction results in a severe violation. We recommend a revision to this approach more consistent with the COM-002-4 penalties. A demonstrated pattern of problems would trigger a Severe VSL, but isolated single events, which did not impact the BES, should not be penalized. (It is hard to argue that not following an OI when one can during an Emergency would not be a severe VSL. Graduated levels could be similar to COM-002-4 R5.) FERC has stated that VSLs should be graded. These are not. Further, intent to perform should count in favor of any entity that is unable to implement an Operating Instruction due to a technical or reliability related concerns. (It is hard to argue that not following an OI when one can during an Emergency would not be Severe. Graduated levels could be similar to COM-002-4 R5.) Regarding Requirement R13, TOPs perform Real-time Reliability Assessments using their EMS Contingency Analysis systems and it is reasonable to expect that such systems would generate results at least every 30 minutes. However, a failure of the EMS or SCADA or of the contingency analysis software should not automatically result in a severe violation. For example, EOP-008-1 R1 allows a TOP two hours following the loss of primary control center functionality to re-establish situational awareness, yet such an event would automatically result in a severe violation of this requirement. We suggest revising R13 to read: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. There is no way to perform a Real – time Assessment without EMS and SCADA given the new definition. In Measure M4, change Generation Operation to Generator Operator. In Measure M5, suggest changing "…Operating Instruction issued by the Transmission Operator(s)" to "…Operating Instructions issued by the Balancing Authority” to match the language in R5. In Measure M6, suggest changing "Balancing Authority" to "Transmission Operator" in the last sentence of the paragraph "If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation." to match the language in R6. Regarding Measure M8, no evidence is needed to show that the Transmission Operator informed the impacted Balancing Authorities. If so, why are they included in R8? Throughout the standard we find "an SOL". In the IRO standards we see "a SOL". Should be “a SOL”. To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. Requirements R1 and R2 appear to create a double jeopardy situation as the TOP is already obligated to comply with all the other requirements for which it is the functional entity. To do so might necessitate issuing Operating Instructions to direct others to act. For example: A TOP needs to issue an Operating Instruction to shed load to comply with EOP. If the TOP does not issue the OI then it won’t comply with its EOP load shed plan. That is a failure to shed load and failure to issue the OI. It is important to clarify R7 by retaining the concept of comparability of actions. For example, the requested TOP or BA should not be expected to implement load shedding if the requesting TOP hasn’t exhausted that option. Suggest changing emergency procedures to comparable emergency procedures. In R8 we agree the TO should inform impacted entities of operations that result in an emergency. However, including operations that “could result in an emergency” is far too broad and might potentially result in limitless notifications. R9 has several issues that need to be addressed. The SDT is utilizing the word negative to limit the need to make notifications, but it is introducing ambiguities in the meaning and determination of negative impact that could result in an unbounded requirement to make notifications. We suggest introducing additional phrases to define negative. Negative impact should mean to reduce the ability to perform an entity’s reliability function. The Measure states this is limited to planned outages while the requirement does not use the word planned. This needs to be resolved. The requirement to coordinate outages would conflict with and cause double jeopardy with the existing COM-001 R3 requirement to coordinate telecom systems within and between areas, including investigating and recommending solutions to problems. It also conflicts with proposed COM-001-2 R10 to within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. The Southwest Outage Report was specific about loss of RTCA. As written the requirement could be interpreted to mean recording loss of a control point or analog value and whether it impacted another NERC entity, and evidence of notification. Consider revising R9 to read: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that utilize the outages equipment in the performance of their reliability functions of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. A different approach would be to split the requirements into a BA and a TOP limited Requirement. The BA would remain the same as the suggested rephrasing above and the TOP would state: Each Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that are within the TOP Area that the TOP Real-time Contingency Analysis tools are not functioning properly and reduces the ability of the TOP to monitor its area. Regarding R10, if a sub-100 kV

facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP's entire area when in reality a subset of facilities may be all that is required. One suggestion rephrasing is Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area… Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. Requirement R16 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R17 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R16 and R17--System Operators should have authority to both approve and disapprove planned outages and maintenance of its monitoring and Real-time assessment (analysis) capabilities. "…maintenance of its monitoring and analysis capabilities." What is "its" referring to? The Rationale isn't clear on this either.
No
To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
No
To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, however, the standard's use of "Operational Planning Analysis" is a revision to its definition.
No
We do not agree with retiring PER-001 R1. This requirement requires operating personnel to have the authority to shed load without consulting non-operating management personnel. There have been instances where load shedding was delayed by non-operating managers or attempts to seek permission to shed load. The System Operator is responsible for maintaining a reliable system in Real-time and they should have full authority to shed load. The SDT reference to the FERC Order does not apply to PER-001. We do not agree with retiring TOP-002 R19. R19 requires the TOP to have an accurate model. The Planning Coordinator model may not be suitable for operations. There are scripts that can convert the Planning model into an Operations model, but these are not uniformly available. The new requirements for conducting an Operating Planning assessment and Real Time Assessment imply that operations has an accurate model. Referring to MOD-033 does not properly support retirement. MOD-033 places a requirement on the PC to have a model but does not require the PC to provide it to the TOP. The question of who is responsible for accuracy of the Real-time model is not answered in MOD-033. The fact that the TOP has to provide behavior data to the PC does not mean it has an accurate model. Agree with retiring TOP-004 R5 requiring remaining connected to the Grid, but suggest the justification is in the proposed TOP-0013 R14 and R15. Agree with retiring TOP-006 R4 but do not agree with the justification pointing to TOP-003. TOP-006 R4 requires a load forecast to be completed for Operational Planning. The justification states this, but it should point to Operational Planning TOP-002-4 R1 and R2. Agree with retiring TOP-006 R6 but do not agree with the justification pointing to BAL-005 frequency metering. TOP's monitor line flows, voltages, SOL and IROL. These items have nothing to do with BAL standards. This requirement sets the stage for situational awareness and monitoring tools. The better reference is TOP-001 R10 which requires the TOP to monitor.
30 minutes is appropriate and consistent with the current NERC EAP guidelines for monitoring and control functionality under normal operating conditions. However, exceptions need to be afforded for EMS system failures and unplanned Control Center outages and/or evacuations, or system blackout, e.g., Hurricanes Katrina, Ike, and Sandy, 2003 Northeast Blackout, 2012 Southwest Blackout. See EOP-004-2 — Attachment 1, Standard EOP-008-1 — Loss of Control Center Functionality, Standard COM-001-2 — Communications (R9), Standard EOP-005-2 — System Restoration from Blackstart Resources, Standard EOP-008-1 — Loss of Control Center Functionality.
Yes
The SOL Whitepaper provides a good example of evaluating system performance. However, it implies that the continuous thermal rating is a hard limit. A Rating Authority may establish applicable pre-contingency thermal limits that are higher than the continuous rating under specific circumstances and do not result in equipment damage. The acceptable pre-contingency performance defined on page 2, item (b) can be written as "All Facilities shall be within their pre-Contingency thermal limits" rather than "All Facilities shall be within their Normal (continuous) Facility Ratings and thermal limits." This is consistent with the methodology for voltage limits listed on page 2, item (c). From an operational perspective, it is not practical to cover any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operating plans must protect against that. Operationally you need to protect against the loss of units regardless of cause.

No
IRO-008-2: R5 requires a real-time assessment every 30 minutes. The VSL is graduated in 5 minute increments. The VSL does not specify the period being measured. The existing IRO-008-1 utilizes a 24 hour sampling in the existing VSL. A similar approach should be used. Each VSL should be checking the completed assessments in a 24 hour period and that the periodicity was within a time bound. So VSL Low would be: The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes OR for any sample 24 hour period within the 30 day retention period, a Real-time Assessment was not conducted for one 30-minute period within that 24-hour period. IRO-014--In the VSL Table repeat the header row for all pages containing the VSL table. IRO-014 R6 (Severe VSL) : in order to be consistent with other standards, change the tense of the verb "exists" to "existed". IRO-017-- R2 VRFs should be Medium, not Low. This is a performance requirement. TOP-001 R3 thru R6 VSLs--an Operating Instruction applies to both Normal and Emergency operations. Therefore the VSL should be graduated similarly to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is Moderate VSL. In the VSL Table, for R3 and R5 (Severe VSL), suggest changing the sentence to "The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator when such an action could have been physically implemented and would not have violated safety, equipment, regulatory or statutory requirements." In the VSL Table for R7 (Severe VSL), suggest changing the sentence to "The Transmission Operator or Balancing Authority did not provide assistance to Transmission Operators, if requested, when the requesting entity had implemented its emergency procedures when such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements." In the VSL Table for R8 (all VSL levels) change the tense of the verb "result in" to "resulted in, or could have resulted in …." to match the rest of the VSL that is written in the same tense.
No
Individual
Greg Froehling
Rayburn Country Electric Cooperative
No
I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3. Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is “Interconnection Reliability Operations and Coordination” and the purpose statement for TOP-001-3 is “To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: • Reliability Coordinator, • Balancing Authority, • Transmission Operator Receiving Entity Any one of the following functions: • Balancing Authority, • Transmission Operator, • Transmission Service Provider, • Generator Operator, • Load Serving Entity • Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Yes
Yes
No
Similar to my comments on IRO-001 and TOP-001 I think this could be combined with TOP-003-3 in a similar manner. GROUP 1 Any of the following: Reliability Coordinator Balancing Authority Transmission Operator GROUP 2 Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: (Maintain the use of general specifications only, detailed specificity can be within each functional entities published data specification) R2. GROUP 1 shall distribute its data specification to entities that have data required by GROUP 1 to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Yes

Yes
No
I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3. Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is “Interconnection Reliability Operations and Coordination” and the purpose statement for TOP-001-3 is “To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: • Reliability Coordinator, • Balancing Authority, • Transmission Operator Receiving Entity Any one of the following functions: • Balancing Authority, • Transmission Operator, • Transmission Service Provider, • Generator Operator, • Load Serving Entity • Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Yes
No
Similar to my comments on IRO-001 and TOP-001 I think this could be combined with IRO-010 in a similar manner. GROUP 1 Any of the following: Reliability Coordinator Balancing Authority Transmission Operator GROUP 2 Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: R2. GROUP 1 shall distribute its data specification to entities that have data required by (GROUP 1) to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Yes
Yes
No Comment
No Comment
Yes
No
: I would reinforce my support for reduction of standards by consolidation of requirements that use nearly identical if not identical language by creating role based groups of functional entities. I believe it makes a requirement clearer to understand since it is found only once within the NERC standards not in 2 or 3 different standards. It makes training easier as well, allowing the focus to be on the required action.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC.
Yes
Yes
Yes
Yes
Yes

No
CenterPoint Energy believes that any coordination of a Planning Assessment between appropriate entities is covered in TPL-001-4 R2, R3, and R8. Furthermore, CenterPoint Energy feels the Reliability Coordinator is a Real-Time function per the NERC Functional Model and should not have a compliance responsibility in coordination of a Planning Assessment between the Planning Coordinator and Transmission Planner. CenterPoint energy recommends removing IRO-17-1 R3 and R4.
No
CenterPoint Energy believes that some of the items in the proposed definition of Real-time Assessment are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations.” These are encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances. CenterPoint Energy believes the proposed language in R1, “…shall act, or direct others…” brings in new compliance concerns that were not present in the previous versions of TOP-001, R1. CenterPoint Energy recommends returning to the language in previous versions stating, “Each Transmission Operator shall have the responsibility and clear decision making authority to take whatever actions are needed to ensure reliability…” If the SDT agrees with this approach, CenterPoint Energy recommends conforming changes to TOP-001-3 R2 and IRO-001-4 R1 for the Balancing Authority and Reliability Coordinator’s responsibility, respectively. CenterPoint Energy believes inconsistencies exist between R1 and R3. R1 states, “Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions…” A NERC defined Transmission Operator Area is the collection of Transmission assets over which the Transmission Operator is responsible for operating. R3 states, “Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s)…” BAs, GOPs, DPs, and LSEs do not fall into a Transmission Operator’s Transmission Operator Area as defined. CenterPoint Energy recommends the SDT review the language in R1 and R3 to determine if any modifications are required to remedy this inconsistency. CenterPoint Energy believes R7 is redundant with issuing and following Operating Instructions as described in TOP-001-3 R1 and IRO-001-4 R1. If assistance is needed under emergency or anticipated emergency conditions, the Transmission Operator or the Reliability Coordinator will issue an Operating Instruction as described in TOP-001-3 R1 or IRO-001-4 R1, respectively. CenterPoint Energy recommends deleting this Requirement. CenterPoint Energy believes R10 is vague in its expectation of monitoring Facilities of neighboring Transmission Operator Areas to maintain reliability. CenterPoint Energy believes it is the Reliability Coordinator’s responsibility to monitor and address seams issues that may extend from one Transmission Operator Area to another Transmission Operator Area. CenterPoint Energy recommends the following change to the language of the Requirement or reassigning the Requirement to the Reliability Coordinator: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.
No
CenterPoint Energy believes that some of the items in the proposed definition of Operational Planning Analysis are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations” as these would be encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances.
Yes
Yes
Yes
Yes
CenterPoint Energy agrees with 30 minutes being the correct periodicity for performing Real-time Assessments.
Yes
At a high level, CenterPoint Energy supports the SOL Exceedance White Paper; however, the Company has concerns regarding two main issues identified below. 1) SOL Performance Summary Chart (Page 4): The ERCOT Region operates such that the continuous Pre-Contingency flow never exceeds the 24hr rating. For reliability purposes, CenterPoint Energy believes Pre-Contingency flow in any range above the 24hr rating is not acceptable and recommends the SDT revise the chart accordingly. 2) Steady State Voltage Limit Exceedance (Page 5): The second sentence states, “Both normal and emergency voltage limits are established that respect the Transmission Owner or the Generation Owner’s Facility Ratings Methodology per approved FAC-008-3.” CenterPoint Energy does not agree that normal and emergency voltage limits are established using the Facility Ratings Methodology required in FAC-008-3. For example, FAC-008-3 R8.2 refers specifically to a Thermal Rating. Additionally, the NERC definitions of Normal and Emergency Ratings refer to “electrical loading, usually expressed in megawatts…” which indicates a Thermal

Rating. While CenterPoint Energy agrees that normal and emergency voltage limits are established, it is through other means outside of FAC-008-3; therefore, CenterPoint Energy recommends removing this sentence.
Yes
CenterPoint Energy is concerned with the existing NERC defined term Transmission Operator Area being introduced in the TOP Standards as it is currently written. Transmission Operator Area: The collection of Transmission assets over which the Transmission Operator is responsible for operating. In the ERCOT region individual Local Control Centers operate Transmission assets under the direction of ERCOT ISO while both are jointly registered Transmission Operators under a Coordinated Functional Registration. CenterPoint Energy recommends a revised definition under Section D, Regional Variances to address this established joint responsibility. The revised definition would read as follows: Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
IRO-008 R6: The Rationale box says that the “language changed from IROL exceedance to Emergency…” But the language in the draft standard actually uses IROL exceedance and not Emergency
Yes
Yes
IRO-014 R9: There are one too many “be”s, “cannot be physically be implemented”
Yes
Yes
Yes
Yes
Yes
Yes
Yes
We agree with the 30 minute periodicity
No
Yes
No
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Yes
AECI supports comments posted by the SERC OC Work Group
No
AECI supports comments posted by the SERC OC Work Group
No
AECI supports comments posted by the SERC OC Work Group

Yes
AECI supports comments posted by the SERC OC Work Group
No
AECI supports comments posted by the SERC OC Work Group
Yes
No
FOR: TOP-001-3, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group. FOR: TOP-001-3 draft 1 clean – All Measures, including this SDT's other posted draft Standards for Comment COMMENT: This Standard, along with all others revised by this project's Drafting Team, appears to word the Measures as Requirements. AECI believes the following examples represents changes that would be more conformant with other NERC Standard revisions: REPLACE: "M1. Each Transmission Operator shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area." WITH: "M1. Examples of evidence may include, but is not limited to: dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that may be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area." FOR: TOP-001-3 draft 1 clean, all references to Load-Serving Entity REMOVE: "Load-Serving Entity" from: Applicability Section 4.5, Requirement R3 and Measurement M3, Requirement R4 and Measurement M4, Requirement R5 and Measurement M5, Requirement R6 and Measurement M6. RATIONALE: See NERC Website, Program Areas & Departments, Compliance & Enforcement, Compliance Analysis and Certification, Risk-Based Registration Initiative, "RBR Design 20140602 FINAL", "Appendix A – Risk-Based Registration Threshold Reviews", pages A-3 thru A-6, Section "Load-Serving Entity", on recommendations for removal based upon lack of Reliability Related Functions performed. FOR: TOP-001-3 draft1 clean, definition for Reliability Directive REPLACE: Rationale for definition for Reliability Directive being dropped WITH: Earlier definition for Reliability directive RATIONALE: AECI strongly advises this SDT and all of Industry, to reconsider this current draft's implication that all Operating Instructions are of equal weight, pertaining to options for discussion, where equally or more effective solutions could and should be made available for discussion by the issuer. This current draft's language does not allow options for reconsideration, when FERC itself often cites possible solutions by closing with "or an equally effective and efficient solution". We earnestly plead with the SDT to carefully reconsider all instances where their wording choices currently bind the recipients of any Operating Instruction with absolutely no choice beyond blind complicity in all instances where the Instruction is physically feasible, safe, and legal. AECI believes such language, executed literally, unnecessarily exposes Responsible Entities to extreme financial burden, with rare benefit to BES Reliability. This is true where equally reliable yet more cost-effective solutions in fact existed, yet could not be proposed without the Operating Instruction's recipient risking violation in several of these drafted Requirements. Please note that AECI does agree that there could be times where the Issuer, particularly RCs in light of rapidly deteriorating BES Conditions, need the authority to issue some Operating Instructions that allow no discussion beyond these conditions currently cited. Yet we firmly believe the vast majority of Operating Instructions should not carry this currently-drafted weight of no recourse upon the issuer or recipient. FOR: TOP-001-3 draft 1 clean, definition of Real-time Assessment COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller Responsible Entities to avoid unnecessary cost of compliance where Real-time Assessments are required. COMMENT: We recommend the Real-time Assessment and Operational Planning Analysis definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,…' RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of "may" provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-001-3 draft 1 clean, Effective Date COMMENT: In requirements where Real-Time Assessment was not currently required, AECI believes newly-applicable entities should be provided with 36 months to become compliant, due to time necessary for smaller entities to research, budget, and enlist in third-party services, then sufficiently train their Operators to effectively utilize their new tool for reliability and compliance. FOR: TOP-001-3 draft 1 clean, Requirements R1 and R2 CAUTION: These requirements appear to dictate that no action upon the BES will be issued in any manner outside the definition of an Operating Instruction. While AECI believes the underlying intent within this language is that all changes to the BES take place with recorded three-part communications, R3 in conjunction with R1 and R2, collectively imply dictatorial rule of every issuer over every recipient any time any BES element's state changes due to an Issuer's Operating Instruction. FOR: TOP-001-3 draft 1 clean, Requirement R3 and R5 (absolute deal-breaker for AECI) REPLACE: "statutory requirements" WITH: "statutory requirements, or has no equally or more effective alternative" RATIONALE: For most routine Operating Instructions, both Issuers and Recipients of Operating Instructions should be provided the option to have equally or more effective solutions discussed prior an ultimate action being taken. FOR: TOP-001-3 draft 1 clean, Requirement R4 PROPOSED INSERTION: a new R4, immediately following R3 R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety,

equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations] RATIONALE: This new R4, essentially equivalent to R3 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R3 proposed change accepted, the SDT and Industry may not agree that this "no further discussion" Requirement is necessary under any circumstances. We only offer it as an optional companion of the R3 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R4 (not our proposed R4 insertion) REPLACE: "reasons shown in Requirement R3." WITH: "reasons shown in Requirement R3, with exception of equally or more effective solutions." RATIONALE: AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R6 PROPOSED INSERTION: a new R7 (this R7 numbering assumes a new R4 was similarly inserted) R7. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations] RATIONALE: This new R7, essentially equivalent to draft R5 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R5 proposed change accepted, the SDT and Industry may not agree that this "no further discussion" Requirement is necessary under any circumstances. We only offer it as an optional companion of the R5 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R6 (original draft R6) REPLACE: "issued by that Balancing Authority." WITH: "issued by that Balancing Authority citing one of the specific reasons shown in Requirement R5, with exception of equally or more effective solutions." RATIONALE: Consistency with R4 AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R7 (deal-breaker for AECI) COMMENT: AECI fully agrees with this requirement's preceding rationale, where insertion of "Effective' was noted. However AECI does not agree with current R7 language that omits the referenced inclusion. As suggested earlier under R3 and R5, AECI strongly recommends that industry be afforded opportunity to raise equally or more effective solutions for discussion as part of requesting and lending assistance, over blind compliance for any requested action this is physically possible, safe and legal. FOR: TOP-001-3 draft 1 clean, Requirement R8 (deal-breaker for AECI) REPLACE: "impacted" WITH: "known impacted" RATIONALE: True extent of impact may not be obvious to a responsible entity at all times. FOR: TOP-001-3 draft 1 clean, Requirement R9 (deal-breaker for AECI) REPLACE: "outages" WITH: "planned outages" REPLACE: "negatively impacted" WITH: "known negatively impacted" RATIONALE: Consistency of this Requirement's language with its corresponding measurement and VSL. Also, the extent of negative impact for data absence is practically impossible to gauge, due to the current complexity of data being circulated upstream of an RC. Notification of your RC should be sufficient. FOR: TOP-001-3 draft 1 clean, Requirement R10 (deal-breaker for AECI) REPLACE: "Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area." WITH: "Each Transmission Operator shall monitor Facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas – including sub-100 kV facilities and the status of Special Protection Systems, Functionally needed to maintain BES reliability." RATIONALE: Scope of NERC Requirements should remain pertinent to BES Reliability Functions. FOR: TOP-001-3 draft 1 clean, Requirement R11 COMMENT: This requirement should eventually make its way into a BAL Standard REPLACE: "shall monitor its Balancing Authority Area, including the status of" WITH: "shall include the status of" RATIONALE: The BAL Standards already include an extensive set of requirements pertinent to the included measurements and their quality that is pertinent to performing their reliability function. Blanket inclusion of the same within this Requirement is redundant. Further, this requirement should really be handled in a different manner, perhaps as a rapid modification to an existing BAL requirement. FOR: TOP-001-3 draft 1 clean, Requirement R12 REPLACE: "Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL Tv." WITH: Each Transmission Operator shall monitor the continuous duration of exceeded limits for all identified Interconnection Reliability Operating Limits (IROLs), and act to assure they are returned to normal before to any such duration exceeds their associated IROL Tv. RATIONALE: Rephrased requirement in a positive sense. FOR: TOP-001-3 draft 1 clean, Rationale for Requirement R14 REPLACE: "such an Operating Plan" WITH: "such an Operating Plan, developed per requirements within TOP-002" RATIONALE: This is the first occurrence of the term "Operating Plan" within the Requirements of this TOP Standard. While the current Rationale for Requirement R14 does reference this SDT's white paper, the reader is currently left wondering if this is a hidden requirement for development of Operating Plan(s), or whether the requirement actually exists elsewhere within the body of NERC Standards. FOR: TOP-001-3 draft 1 clean, Requirement R15 REPLACE: "of its actions to" WITH: "of its actions taken to" RATIONALE: Clarity – to differentiate that this requirement is not a repeat, to inform the RC of action(s) developed within all Operating Plans, but rather the TOP's anticipated or actual action taken to mitigate the SOL exceedance that triggered their activation of that previously communicated Operating Plan.
No
FOR: TOP-002-4, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group FOR: TOP-001-3 draft 1 clean, definition of Operational Planning Analysis COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller

Responsible Entities to avoid unnecessary cost of compliance where Operational Planning Analysis are required. COMMENT: We recommend the Operational Planning Analysis definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,…' RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of "may" provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-002-4, draft 1 clean, Requirement R2 and Measurement M2 REPLACE: (R2) "an Operating Plan(s)" and (M2) "an Operating Plan" WITH: "one or more Operating Plan(s)" RATIONALE: Grammar FOR: TOP-002-4, draft 1 clean, Requirements and Measurements, R4, M4, R5, M5, R7 and M7 COMMENT: These Requirements for BAs really should reside within the BAL Standards.
No
AECI supports comments posted by the SERC OC Work Group
Yes
AECI supports comments posted by the SERC OC Work Group
Yes
AECI supports comments posted by the SERC OC Work Group
No comments
No
No
AECI supports comments posted by the SERC OC Work Group
No
Individual
Tom Haire
Rutherford EMC
Yes
No
In the Table of Compliance Elements, the severity and risk for R5 is medium with only a Severe VSL. All other requirements in this standard are low and have graduated levels of severity. In IRO-10, the same failure has graduated levels of severity. This is inconsistent and should be rectified.
No
See comments on TOP-003.
Group
FRCC Operating Committee (Member Services)
John A. Libertz
No
R1 – Requirement R1 is not needed. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, we recommend removal of the Operations Planning horizon to narrow the focus of intent. As defined, the term Operating Instruction applies only to "Real-time operation of the interconnected BES." In addition, the term Operating Instruction is too broad in scope because it applies to any "change in state, status, output, or input

of an Element of the BES." The amount of documentation required for evidence would be very burdensome. R2 – TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. R3 – TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. In addition, a correction is needed to refer to R1, instead of R2, when referencing the Operating Instruction issued by its RC.
No
We recommend the removal of the Operations Planning horizon from this Standard. The Purpose of this Standard states "Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions." This would not apply in the Operations Planning horizon. R1 – This requirement is duplicative with currently enforced COM-001-1.1 R1 and future COM-001-2 R1. The communication with GOPs should be done through BA because the BA/TOP should be aware of actions being taken in regards to generation. The term "voice communications" should be singular. R2 – The term "data links" lends to the idea of an electronic submittal. PCs, TOs, GOs, LSE, DPs and TPs do not need to provide real time data. We recommend the language be modified to allow for data links with BAs and TOPs. The requirement could also state that TOs, GOs, GOPs, LSEs, and DPs shall provide, or have provisions for, the data via their host BA/TOP. We recommend PCs and TPs be removed from this requirement. R3 – The language "to approve" does not seem to cover the full spectrum of authority needed by the RC. We recommend the following language: "Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools." R4 – To eliminate confusion, we recommend creating two requirements with the following language: Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R5 – This requirement does not seem to be measurable. What does "over a redundant and highly reliable infrastructure" mean? What is an acceptable level of synchronism and reliability? How are these terms going to be measured? We recommend adding an additional requirement stating: "Each RC shall monitor identified phase angle limitations within its RC Area." This will eliminate the need for the phase angle language within the new Real-time Assessment term definition.
No
As defined, the term "Operating Plan" refers to a formal document or plan must be submitted. There are existing other requirements and processes in place within our region that provide the necessary data (via automated tools) to perform the next-day study. Requiring a submission of an "Operating Plan" would require the data to be manually entered and result in additional man-power usage with no benefit to reliability. We recommend the following language: "Each Reliability Coordinator shall review the operating data for next-day operations provided by its Transmission Operators and Balancing Authorities." R3 – This requirement implies a formal "Operating Plan" must be produced each day. See comments for IRO-008-2 R2 above. We recommend the following language: "Each Reliability Coordinator shall document the coordination of actions for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the data for the next-day provided by its Transmission Operators and Balancing Authorities." R4 - What does "impacted" mean and why is it not limited to entities who are required to take action (TOPs, BAs, GOPs, etc.)? R6 - Is this meant to refer to the Operating Plan developed in R3? Need clarification. Rationale for R6 discusses use of the term Emergency, yet the term is not used in R6 or R7. The words "as indicated in its Operating Plan" add no value to the statement requiring notification to the named entities. Recommend deletion. R7 - Change "to deal with" to "to prevent or mitigate." Add clarification because the TOP and BA are also issuing Operating Instructions. It should be clear that the RC is a back stop for TOP and BA. R8 - Same as R6. Delete "as indicated in its Operating Plan". Compliance section 1.3 – Data Retention: Recommend changing "the most recent three months for voice recordings" to "90 days" to eliminate disparity with non-30 day months. This also will allow automation of deletion processes. It will also make the second paragraph match the third paragraph which requires 90 days for R5 voice recordings.
No
R1.1 - Does this mean a generic type of data required or a detailed list of data points? R3 - Why is LSE included with the planned retirement of LSEs? Why is TP and PC included in this requirement? The TP and PC horizon timeline does not fit within the Operations Planning horizon.
No
R1 - Change the word "other" to "adjacent." R1.5 - Similar language was removed from IRO-001-1.1 R3 with the justification "The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act." The same logic should be applied here and this requirement should be deleted. R1.6 - Is the intent for this requirement for adjacent RC's to have a weekly call or that all RC's within the Eastern Interconnection participate in a weekly call? Change R1.6 to state "at least weekly" to synchronize with R4. R2 – Concern with term "Operating Plans"

utilized throughout proposed Standards. We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R2.1 - Many of the new requirements imply daily creation of Operating Plans, yet this requirement states annual review. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.2 - Seems to imply that each updated Operating Plan needs written agreement and we don't believe that adds to reliability. We believe documents should be reviewed and updated as necessary. The way this requirement is written, if any modifications are made to an Operating Plan, a written agreement is needed. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.3 - We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R5 – What is the driver to change from Adverse Reliability Impact to the term Emergency? Seems to move away from focusing on IROL type scenarios. As defined, the term Emergency refers to "any abnormal system condition that requires automatic or immediate manual action…" The use of this term is too broad. We have a concern that too much communication may be required for situations that do not need to be communicated between RCs. We would recommend keeping the term Adverse Reliability Impact. Please provide examples of instances where you would want the RC to RC communication to take place. Also provide examples of what is not considered an Emergency. R5–R9 What situation or need is the SDT trying to fix with these requirements? The term "Emergency" could be pulling in balancing actions instead of reliability needs. These requirements are inter-related and language seems to add confusion. This series of requirements tends to deal with disagreement between RCs and not the focus of developing a coordinated action plan to resolve the Emergency. Language in current standards seems to be a better fit. R6, R8, and R9 seem duplicative. Existing language in IRO-016-1 for communication was more cooperative and the new language is more directive driven. We believe there should be a requirement that the problem is discussed and a coordinated action plan be developed (language in existing IRO-016-1). The term action plan is utilized in R7 which is a good term for Real-time Assessment, but other requirements utilize Operating Plan. R9 – What does implemented its emergency procedures mean? Is this related to the Operating Plan or action plans? It uses the term "requesting entity"…does this refer to a situation when a BA/TOP requests assistance from the RC and their RC requests assistance from another RC? Or does "requesting entity" refer to the requesting RC? It should explicitly state requesting RC if that is what is meant. Why is "emergency" not capitalized in this requirement?
No
R1.3 and R1.5 seem to be stating the same thing just using different language. Please clarify the difference between the 2 requirements. R1.1.2 - Recommend to delete the language "prior to submitting to RCs". Each RC should be able to define their process to fit their area. M2 – Could an attestation from the RC that each TOP and BA followed the outage coordination process be evidence? A concern on what the evidence would look like if this was not feasible. R3 & R4 – The PC's and TP's planning horizon is Year One and beyond. They do not cover the Operations Planning time horizon, so how do R3 and R4 practically apply to the RC. The PC's and TP's have the responsibility to develop "corrective action plans" for identified issues or conflicts for the time frame they are studying. Recommend to strike R3 and R4 from this standard. If keeping R3, then it should be in the TPL standard, not the IRO standard.
No
Definition for Real-time Assessment: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word "contracted" with "arranged". R1 - This could place a huge burden for evidence control on the entities because Operating Instruction is altering the state of any BES Facility. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, recommend removal of the Operations Planning horizon tasks and narrow down focus of intent. The term "Operating Instruction" is defined for Real-time operation. SDT should review the term Transmission Operator Area because it would not include LSE, DPs, etc. R2 – Please see comments for TOP-001-3 R1 above. R3 – Operating Instruction is too broad of a definition that would require a huge amount of evidence. The defined term refers to too many circumstances and not only to "emergency conditions." At a minimum, this requirement should only refer to the Real-time Operations time horizon. We also recommend LSE and DPs be removed from this requirement. The LSE's cannot perform any corrective action. Refer to Functional Model for LSEs and DPs. In addition, there is a current proposal to remove LSEs from registry. R4 - Please see comments for TOP-001-3 R3 above. R5 - Please see comments for TOP-001-3 R3 above. R6 - Please see comments for TOP-001-3 R3 above. R7 - TOP-001-1a R6 stated "available emergency assistance" and the new requirement states "shall assist". Recommendation would be to change the language to "if requested and available." The RC will take the appropriate actions if there is a reliability related need. Assistance should be available to BAs as well, current wording is not symmetrical. R8 – The requirement is defining operations that could result in an Emergency and may be defining the term Emergency. The examples given are not necessarily considered an Emergency, unless they were "significant" changes and unplanned. Even then, the actions may still not constitute an Emergency. R9 – M9 refers to planned outages. If that was the intent, the word "planned" should be added to the requirement. SW Outage Report Recommendation 15 specifically addressed RTCA. This requirement was expanded beyond the recommendation. Does "monitoring and assessment capabilities" refer to Real-time Assessment capabilities? New proposed language is too broad. Recommendation would be to focus on loss of RTCA capabilities. R10 – To eliminate confusion, we recommend creating two requirements with the following language: "Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area." "Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL

exceedances within its Transmission Operator Area." The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R13 - It is important for Real-time Assessments to be performed, however, it is not important who does them. Recommend language: "Each Transmission Operator shall ensure a Real-time Assessment is performed at least once every 30 minutes." This language allows other entities (including the RC as was the case in IRO-008-1 R2) to complete the assessment, but maintains the responsibility on the TOP as desired in the rational for R13. This falls in-line with the new definition for Real-time Assessment. R14 - The term "Real-time monitoring" is not a defined term. Existing and potential operating conditions are included in the Real-time Assessment defined term. As defined, the term "Operating Plan" refers to a formal document referencing a specific scenario or potential SOL exceedance. We have a concern on how the term Operating Plan is utilized throughout the proposed Standards and how they are linked to the OPA and RTA. We recommend changing the requirement to read: "Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified in its Real-time Assessment." R16 & R17 – We recommend the following language: "Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools."
No
Definition for Operational Planning Analysis: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word "contracted" with "arranged". R2 – What are the circumstances for using an Operating Procedure vs an Operating Process? R4.4 – Clarify the use of "Capacity and energy reserve requirements, including deliverability capability ". Are these reliability based terms or commercial? R5 – Please clarify the use of the term "impacted". Does this refer to normal operations or is it intended to capture exceptions to the normal operations? R6 – The amount of documentation would be very burdensome. R7 – The amount of documentation would be very burdensome.
No
R1 – Time Horizon should include Real-Time Operations and Same-Day Operations. R1.1 and R1.2: Does this mean a generic type of data required or a detailed list of data points? R2 – Time Horizon should include Real-Time Operations and Same-Day Operations. R2.1 and R2.2: Does this mean a generic type of data required or a detailed list of data points?
Yes
Yes
Yes
No
Add language to the SOL Exceedance White Paper to state that a SOL can only be exceeded where it has been defined on a TOPs system as is stated in FAC-014-2. Add language to the SOL Exceedance White Paper clarifying that SOLs are only exceeded in Real-time based on actual system conditions and not as a result of the use Real-time assessment tools performing post-contingency analysis. Page 3 – Change the words "SOLs include Facility Ratings…" to "SOLs may be based on Facility Ratings…" Page 4 – SOL Performance Summary bullet 4. Add language "except load shed" to be consistent with operating plan in table 1. Page 8 – Typo in the Operating Procedure definition. The word "operating" should be "operator" in the last sentence.
Yes
1. Special Protection Systems should be addressed in their own requirements. 2. Phase Angle limitations should be greater than 300 kV. 3. The FRCC MS OC would like to thank the TOP/IRO SDT for their time and effort in developing the proposed changes to the NERC Reliability Standards as part of this important initiative. We support the SDT efforts conceptually, and have provided comments on improving the language and clarity of some of the proposed requirements. However we do have some questions and concerns that need to be addressed prior to giving the project our full support.
Individual
Heather Bowden
EDP Renewables North America LLC
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Yes
No
Group
MRO NERC Standards Review Forum
Joe DePoorter
No
R3 is predicated on R2 and only allows entities the inability to perform the issued Operating Instruction based on "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements". The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting "citing one of the specific reasons shown in Requirement R3", as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction.
No
R5. The NSRF does not agree with the ambiguous wording of "over a redundant" and "highly reliable infrastructure". EOP-008-1, R3 requires an RC to have a backup control center facility not dependent on the primary control center. This is the same type of required items within R5. Recommend deleting "over a redundant" in order to remove the similar language and remove the possibility of double jeopardy. Concerning the word of "highly reliable infrastructure", we do not believe that an RC would utilize "slightly reliable infrastructure". This ambiguous wording will be a compliance night mare as it will always be subjective in nature. Recommend deleting "highly reliable infrastructure". A simple recommendation would be to remove the wording of "over a redundant and highly reliable infrastructure" and replace it with "over a system that is not impacted by a single point of failure".
No
The NSRF does not concur with 1) the RC having Operating Plans for next day operations (per R2) as stated in TOP-002-4, R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities… Plus 2) the notification of NERC Registered Entities identified in those plans. The NSRF does not know, for example, how having a requirement to inform someone of an Interchange schedule that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have an Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the IERP only recommends this and it is not a FERC directive or remove Operating Plans and replace with "plans". R5, see question 11 concerning the 30 minute threshold
Yes
No

R1 requires RCs to have Operating Plans to inform "… other RC Areas…". Please note that WECC and TRE only have one RC within their Regions (Peak Reliability and ERCOT, respectfully). Where the Eastern Interconnection has 13 RCs, should this type of Requirements be removed and set up similar as IRO-006-EAST-001? This may also be applicable to R9. R1, R2 and R3 an Operating Plan is defined as "A DOCUMENT that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes". There is no reliability benefit to list Operating Procedures or Operating Processes since they are components of an Operating Plan. Recommend "Operating Procedures or Operating Processes" be deleted.
Yes
No
Comments: In R1 and R2, the wording of "reliability function" is used and the NSRF suggest replacing it with "to maintain system stability". This is more in line with the definition of an Operating Instruction. If "reliability function" is maintained, we believe that any conversation or discussions concerning what the entity's function is, would be construed as an Operating Instruction. We believe this is not the intent of the SDT. R4 is predicated on R3 and only allows entities the inability to perform the issued Operating Instruction based on "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements". The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting "citing one of the specific reasons shown in Requirement R3", as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction. During a real time event, the TOP only cares about the mitigating actions that they have available in order to maintain system stability. If a requested action cannot be accomplished by the requested entity, the TOP will quickly move to their next mitigating action. There is no need for small talk of "why" the requested action cannot be performed. The NSRF believes this was a partial cause of the 2003 blackout. R8. The NSRF understands the intent of R8 and recommends the words "system or equipment" be added prior to operations. Recommended changes provide clarity as, "…of its actual or expected system or equipment operations that result in…". This provides clarity to what type of operations the Requirements is referring to. R8. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected system or equipment operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load. R9 - Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their contingency analysis capabilities after the functionality is lost. Therefore, the requirement should be revised to only address forced or unexpected outages. Recommend that R9 read as: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities R13 - Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains the requirement, the NSRF recommends developing a performance based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example – CPS1 / CPS2 BA performance metrics.
No
R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities… Plus the notification of NERC Registered Entities identified in those plans. The NSRF does not know how, for instance, how having a requirement to inform someone of an Interchange schedule, that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have a (DOCUMENTED) Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the IERP only recommends this and it is not a FERC directive.
No
R3 and R4 need to be reworded as it is believed that it is a request for data from the TOP (R3) and BA (R4) to other entities to be included into the prescribe analysis or assessment. Recommend R3 (and similar for R4) to read as: "Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment".
Yes
Yes

No
N/A
N/A
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes
No
1. R6 rationale says that “exceedance” was changed to “emergency” but the standard shows no change. 2. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 3. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities.
Yes
1. Proposed Requirement R1, part 1.7 rationale does not reference the standards correctly and does not appear to belong to R1.
Yes
No Comments
Yes
No Comments
No
1. R7 – “Effective” is not included in the requirement language as indicated in the rationale. 2. R13 needs additional time for implementation. Recommendation for 3 years from approval. We voted negative on this standard because we think that the implementation period needs to be longer. 3. R14 – There is currently no requirement to have a plan, so how can entities be required to follow a plan they are not required to create? Is a generic SOL mitigation plan satisfactory?
Yes
Yes
Yes
Yes
Yes
No Comments
No
No
Individual
Terry Volkmann
Volkmann Consulting
Yes
Yes
No

IRO-010 should have a 4th requirement that requires the RC to determine and communicate any deficiency of data received back to the applicable entity providing the data. R3 requires the sending of data to the RC, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the RC know if they have enough data, but performance of its real-time processes and tools. The RC should be required to communicate data deficiencies and not rely on the Audit process.
Yes
Yes
Yes
See comments on the SOL Exceedance document
Yes
No
TOP-003 should have additional requirements that requires the TOP or BA to determine and communicate any deficiency of data received back to the applicable entity providing the data. TOP-003 requires the sending of data to the TOP or BA, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the TOP or BA know if they have enough data, but performance of its real-time processes and tools. The TOP or BA should be required to communicate data deficiencies and not rely on the Audit process.
Yes
Yes
Yes
Yes
Figure 1 on page 4 suggests that the TOP is allowed to risk a post contingency exceedance of the short term emergency (STE) rating if there is an Operating Plan. This is a dangerous reliability risk. An Operating Plan should not be an acceptable means to exceed the STE, unless that Transmission Owner's Facility Rating Methodology allows it and agrees to an new STE. The new STE must factor in the response time of the Operating Plan. As stated the document suggests that the Operating Plan can be used with no limitations of exceeding the STE.
Yes
No
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
No
No
Individual
Chris scanlon
Exelon Ccompanies
Yes
Yes
Yes
Yes
Yes
Yes
No
Exelon agrees with all but one aspect of the proposed standard. R18. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits. R18 previously included other entities as identified in the Rational including the LSE, PSE, DP and TSP. The rational statement says deleting these entities is being done "as those entities will receive instructions on limits from the responsible entities cited in the requirement". Exelon Generation believes the GOP belongs in the same category as the above deleted entities for this requirement. We note that “derived limit” is an undefined term. It may be a term of art in the TOP lexicon but it is not commonly used or understood by GOP’s. In dozens of audits, no auditor has been able to tell us (Exelon Generation Company, Nuclear and Fossil) what this means with respect to a generator operator. The TOP may derive limits on the transmission system but in our experience the GOP does not. The GOP provides facility status information, GSU limits etc. that the TOP can use to calculate /model / derive the limits on the transmission system. Providing facility status and following Directives and Operating Instructions is a GOP responsibility, deriving limits implies information about a dynamic system being modeled and evaluated so as to determine the limits to transmission system operation which is a TOP and or a RC responsibility. As background, we point out that the pre version 0 NERC Operating Guide 200 from which this requirement appears to come did not include the GOP and the ver. 0 standard IRO-005 R13 did not include the GOP in the applicability for this standard (all above Rational 18 deleted entities and GOPs were added in IRO-005 R13 text but not included in the applicability for the standard). Changes to the applicability section of IRO-005 that included these entiies was later added via an errata. This issue and a cogent FERC response to it was identified in Order 693 944. TAPS raises an issue with Requirement R13 that states in part “[i]n instances where there is a difference in derived limits,…Load-Serving Entities…shall always operate the Bulk Electric System to the most limiting parameter.” TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load. 950. We [FERC] do not share TAPS’ concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS’ concern in developing the modification of this Reliability Standard.
Yes
Yes
Yes

Yes
No
Individual
Ronnie Hoeinghaus
City of Garland
No
Requirement 1 Concern # 1 The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action – therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1 Replace this proposed requirement with the existing requirements concerning authority. Concern # 2 The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at the time. Recommendation # 2 Replace this proposed requirement with the existing requirements concerning authority.
No
Requirement # 1 Concern is with the portion of the definition of “Operational Planning Analysis” and “Real Time Assessments” that lists “identified phase angle”. It is not clear what “identified” means. “Identified” should mean that the RC will identify representative points across the area for which the RC is responsible – not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
No
Requirement 1 Concern # 1 The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action – therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1 Replace this proposed requirement with the existing requirements concerning authority. Concern # 2 The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at the time. Recommendation # 2 Replace this proposed requirement with the existing requirements concerning authority. Requirement 2 Same concerns as listed under question 7 – Requirement 1 Requirement 10 Concern: “shall monitor Facilities within its TOP Area and neighboring TOP Areas” – The “and neighboring TOP Areas” is too vague and too open to interpretation - should not be left to an auditor’s opinion during an audit situation to determines what facilities and how “deep” into neighboring TOP Areas must be monitored to be compliant. Recommendation: delete “and neighboring TOP Areas” Requirement 13 Concern 1 There is no provision to allow for any number of reasons why a Real-time Assessment might not be completed on a 30 minute cycle without it being a violation – any way one looks at it, “life is not perfect” and an entity (the TOP) should not be fined or spend financial / personnel resources to work through a potential violation every time a Real-time Assessment fails to complete. Concern 2 There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability – all TOPs are not created equal.
No

Requirement 1 Concern There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability – all TOPs are not created equal.
No
Requirement 1 Concern There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing the capability to run the analysis and assessment – all TOPs are not created equal.
Yes
Implementation Plan Concern In the Implementation Plan, IRO-010-2 and TOP-003-3 both have requirements that are intended to go into effect on different dates to allow data specifications to be developed / distributed to entities and those receiving entities have time to gather / format data and send back to the requesting entities. Both effective dates refer to the 1st day of the 1st calendar quarter that occurs either 10 months or 12 months after the approval date (FERC’s approval in the US). Because of the 2 months separation, there is one month in each quarter that if FERC approves the standards in that month, the 10 months & 12 months later will both fall in the same quarter resulting both effective dates starting on the same 1st day of the 1st quarter following. Recommendation: Change language to where the two sets of requirements will go into effect one quarter apart. Définitions Concern is with the portion of the definition of “Operational Planning Analysis” and “Real Time Assessments” that lists “identified phase angle”. It is not clear what “identified” means. “Identified” should mean that the Entity will identify representative points across the area for which it is responsible – not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
No
R1 – Requirement R1 is not needed. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, we recommend removal of the Operations Planning horizon to narrow the focus of intent. As defined, the term Operating Instruction applies only to “Real-time operation of the interconnected BES.” In addition, the term Operating Instruction is too broad in scope because it applies to any “change in state, status, output, or input of an Element of the BES.” The amount of documentation required for evidence would be very burdensome. R2 – TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. R3 – TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. In addition, a correction is needed to refer to R1, instead of R2, when referencing the Operating Instruction issued by its RC.
No
We recommend the removal of the Operations Planning horizon from this Standard. The Purpose of this Standard states “Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.” This would not apply in the Operations Planning horizon. R1 – This requirement is duplicative with currently enforced COM-001-1.1 R1 and future COM-001-2 R1. The communication with GOPs should be done through BA because the BA/TOP should be aware of actions being taken in regards to generation. The term “voice communications” should be singular. R2 – The term “data links” lends to the idea of an electronic submittal. PCs, TOs, GOs, LSE, DPs and TPs do not need to provide real time data. We recommend the language be modified to allow for data links with BAs and TOPs. The requirement could also state that TOs, GOs, GOPs, LSEs, and DPs shall provide, or have provisions for, the data via their host BA/TOP. We recommend PCs and TPs be removed from this requirement. R3 – The language “to approve” does not seem to cover the full spectrum of authority needed by the RC. We recommend the following language: “Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.” R4 – To eliminate confusion, we recommend creating two requirements with the following language: Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R5 – This requirement does not seem to be measurable. What does “over a redundant and highly reliable infrastructure” mean? What is an acceptable level of synchronism and

reliability? How are these terms going to be measured? We recommend adding an additional requirement stating: “Each RC shall monitor identified phase angle limitations within its RC Area.” This will eliminate the need for the phase angle language within the new Real-time Assessment term definition.
No
R2 – As defined, the term “Operating Plan” refers to a formal document or plan must be submitted. There are existing other requirements and processes in place within our region that provide the necessary data (via automated tools) to perform the next-day study. Requiring a submission of an “Operating Plan” would require the data to be manually entered and result in additional man-power usage with no benefit to reliability. We recommend the following language: “Each Reliability Coordinator shall review the operating data for next-day operations provided by its Transmission Operators and Balancing Authorities.” R3 – This requirement implies a formal “Operating Plan” must be produced each day. See comments for IRO-008-2 R2 above. We recommend the following language: “Each Reliability Coordinator shall document the coordination of actions for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the data for the next-day provided by its Transmission Operators and Balancing Authorities.” R4 - What does “impacted” mean and why is it not limited to entities who are required to take action (TOPs, BAs, GOPs, etc.)? R6 - Is this meant to refer to the Operating Plan developed in R3? Need clarification. Rationale for R6 discusses use of the term Emergency, yet the term is not used in R6 or R7. The words “as indicated in its Operating Plan” add no value to the statement requiring notification to the named entities. Recommend deletion. R7 - Change “to deal with” to “to prevent or mitigate.” Add clarification because the TOP and BA are also issuing Operating Instructions. It should be clear that the RC is a back stop for TOP and BA. R8 - Same as R6. Delete “as indicated in its Operating Plan”. Compliance section 1.3 – Data Retention: Recommend changing “the most recent three months for voice recordings” to “90 days” to eliminate disparity with non-30 day months. This also will allow automation of deletion processes. It will also make the second paragraph match the third paragraph which requires 90 days for R5 voice recordings.
No
R1.1 - Does this mean a generic type of data required or a detailed list of data points? R3 - Why is LSE included with the planned retirement of LSEs? Why is TP and PC included in this requirement? The TP and PC horizon timeline does not fit within the Operations Planning horizon.
No
R1 - Change the word “other” to “adjacent.” R1.5 - Similar language was removed from IRO-001-1.1 R3 with the justification “The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act.” The same logic should be applied here and this requirement should be deleted. R1.6 - Is the intent for this requirement for adjacent RC’s to have a weekly call or that all RC’s within the Eastern Interconnection participate in a weekly call? Change R1.6 to state “at least weekly” to synchronize with R4. R2 – Concern with term “Operating Plans” utilized throughout proposed Standards. We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R2.1 - Many of the new requirements imply daily creation of Operating Plans, yet this requirement states annual review. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.2 - Seems to imply that each updated Operating Plan needs written agreement and we don’t believe that adds to reliability. We believe documents should be reviewed and updated as necessary. The way this requirement is written, if any modifications are made to an Operating Plan, a written agreement is needed. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.3 - We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R5 – What is the driver to change from Adverse Reliability Impact to the term Emergency? Seems to move away from focusing on IROL type scenarios. As defined, the term Emergency refers to “any abnormal system condition that requires automatic or immediate manual action…” The use of this term is too broad. We have a concern that too much communication may be required for situations that do not need to be communicated between RCs. We would recommend keeping the term Adverse Reliability Impact. Please provide examples of instances where you would want the RC to RC communication to take place. Also provide examples of what is not considered an Emergency. R5–R9 What situation or need is the SDT trying to fix with these requirements? The term “Emergency” could be pulling in balancing actions instead of reliability needs. These requirements are inter-related and language seems to add confusion. This series of requirements tends to deal with disagreement between RCs and not the focus of developing a coordinated action plan to resolve the Emergency. Language in current standards seems to be a better fit. R6, R8, and R9 seem duplicative. Existing language in IRO-016-1 for communication was more cooperative and the new language is more directive driven. We believe there should be a requirement that the problem is discussed and a coordinated action plan be developed (language in existing IRO-016-1). The term action plan is utilized in R7 which is a good term for Real-time Assessment, but other requirements utilize Operating Plan. R9 – What does implemented its emergency procedures mean? Is this related to the Operating Plan or action plans? It uses the term “requesting entity”…does this refer to a situation when a BA/TOP requests assistance from the RC and their RC requests assistance from another RC? Or does “requesting entity” refer to the requesting RC? It should explicitly state requesting RC if that is what is meant. Why is “emergency” not capitalized in this requirement?
No

R1.3 and R1.5 seem to be stating the same thing just using different language. Please clarify the difference between the 2 requirements. R1.1.2 - Recommend to delete the language “prior to submitting to RCs”. Each RC should be able to define their process to fit their area. M2 – Could an attestation from the RC that each TOP and BA followed the outage coordination process be evidence? A concern on what the evidence would look like if this was not feasible. R3 & R4 – The PC’s and TP’s planning horizon is Year One and beyond. They do not cover the Operations Planning time horizon, so how do R3 and R4 practically apply to the RC. The PC’s and TP’s have the responsibility to develop “corrective action plans” for identified issues or conflicts for the time frame they are studying. Recommend to strike R3 and R4 from this standard. If keeping R3, then it should be in the TPL standard, not the IRO standard.
No
Definition for Real-time Assessment: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word “contracted” with “arranged”. R1 - This could place a huge burden for evidence control on the entities because Operating Instruction is altering the state of any BES Facility. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, recommend removal of the Operations Planning horizon tasks and narrow down focus of intent. The term “Operating Instruction” is defined for Real-time operation. SDT should review the term Transmission Operator Area because it would not include LSE, DPs, etc. R2 – Please see comments for TOP-001-3 R1 above. R3, R4, R5, and R6 – Operating Instruction is too broad of a definition that would require a huge amount of evidence. The defined term refers to too many circumstances and not only to “emergency conditions.” At a minimum, this requirement should only refer to the Real-time Operations time horizon. We also recommend LSE and DPs be removed from this requirement. The LSE’s cannot perform any corrective action. Refer to Functional Model for LSEs and DPs. In addition, there is a current proposal to remove LSEs from registry. R7 - TOP-001-1a R6 stated “available emergency assistance” and the new requirement states “shall assist”. Recommendation would be to change the language to “if requested and available.” The RC will take the appropriate actions if there is a reliability related need. Assistance should be available to BAs as well, current wording is not symmetrical. R8 – The requirement is defining operations that could result in an Emergency and may be defining the term Emergency. The examples given are not necessarily considered an Emergency, unless they were “significant” changes and unplanned. Even then, the actions may still not constitute an Emergency. R9 – M9 refers to planned outages. If that was the intent, the word “planned” should be added to the requirement. SW Outage Report Recommendation 15 specifically addressed RTCA. This requirement was expanded beyond the recommendation. Does “monitoring and assessment capabilities” refer to Real-time Assessment capabilities? New proposed language is too broad. Recommendation would be to focus on loss of RTCA capabilities. R10 – To eliminate confusion, we recommend creating two requirements with the following language: “Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” “Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R13 - It is important for Real-time Assessments to be performed, however, it is not important who does them. Recommend language: “Each Transmission Operator shall ensure a Real-time Assessment is performed at least once every 30 minutes.” This language allows other entities (including the RC as was the case in IRO-008-1 R2) to complete the assessment, but maintains the responsibility on the TOP as desired in the rational for R13. This falls in-line with the new definition for Real-time Assessment. R14 - The term “Real-time monitoring” is not a defined term. Existing and potential operating conditions are included in the Real-time Assessment defined term. As defined, the term “Operating Plan” refers to a formal document referencing a specific scenario or potential SOL exceedance. We have a concern on how the term Operating Plan is utilized throughout the proposed Standards and how they are linked to the OPA and RTA. We recommend changing the requirement to read: “Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified in its Real-time Assessment.” R16 & R17 – We recommend the following language: “Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.”
No
Definition for Operational Planning Analysis: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word “contracted” with “arranged”. R2 – What are the circumstances for using an Operating Procedure vs an Operating Process? R4.4 – Clarify the use of “Capacity and energy reserve requirements, including deliverability capability “. Are these reliability based terms or commercial? R5 – Please clarify the use of the term “impacted”. Does this refer to normal operations or is it intended to capture exceptions to the normal operations? R6 and R7 – The amount of documentation would be very burdensome.
No
R1 – Time Horizon should include Real-Time Operations and Same-Day Operations. R1.1 and R1.2 - Does this mean a generic type of data required or a detailed list of data points? R2 – Time Horizon should include Real-Time Operations and Same-Day Operations. R2.1 and R2.2 - Does this mean a generic type of data required or a detailed list of data points?
Yes
Yes

Yes
Seminole agrees with 30 minutes
No
Add language to the SOL Exceedance White Paper to state that a SOL can only be exceeded where it has been defined on a TOPs system as is stated in FAC-014-2. Add language to the SOL Exceedance White Paper clarifying that SOLs are only exceeded in Real-time based on actual system conditions and not as a result of the use Real-time assessment tools performing post-contingency analysis. Page 3 – Change the words “SOLs include Facility Ratings…” to “SOLs may be based on Facility Ratings…” Page 4 – SOL Performance Summary bullet 4. Add language “except load shed” to be consistent with operating plan in table 1. Page 8 – Typo in the Operating Procedure definition. The word “operating” should be “operator” in the last sentence.
Yes
Yes
1. Special Protection Systems should be addressed in their own requirements. 2. Phase Angle limitations should be greater than 300 kV. 3. Seminole would like to thank the TOP/IRO SDT for their time and effort in developing proposed changes to the NERC Reliability Standards as part of this important initiative. We support the SDT efforts conceptually, and have provided comments on improving the language and clarity of some of the proposed requirements. However we do have some questions and concerns that need to be addressed prior to giving the project our full support.
Individual
Glenn Pressler
CPS Energy
No
"Transmission Planner” should be stricken from requirement R3, as the Transmission Planner is already obligated to provide the Planning Assessment to the Planning Coordinator through TPL-001-4. The requirement R4 should be stricken entirely, since this study is already performed and reported in the Planning Assessment required by TPL-001-4
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP (“ICLP”) believes the changes made to IRO-001-4 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions – not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of IRO-001-4. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business – by far the larger category – must be excluded. IRO-001-4 R1 has simply removed the limitation that the applicable Operating Instructions are those made during an Emergency or Adverse Reliability Impact. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirement R1 specifically limiting its applicability to a set of defined circumstances. A better

method may be to require the RC to identify the Operating Instruction as “critical” to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP does not agree with the removal of the qualifier in R3 that the Operating Instruction recipient must notify the issuer “upon recognition” of its ability to perform it. This language was added to account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith – but finds out later they cannot. As such, the qualifier should be reinstated.
No
Requirement R4 calls for the Reliability Coordinator to monitor certain sub-100 kV facilities that to ensure operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason – and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied unevenly across Reliability Coordinators; which works against the fundamental intent of reliability standardization.
No
R1.1 allows the Reliability Coordinator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason – and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied unevenly across Reliability Coordinators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R3). The RC should provide those specifications and processes under Requirement R1 as is the case in the existing standard. If there is an issue with the term “mutually agreeable”, the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
No
ICLP believes that this is a perfect example of a standard that should inherently assume that a mostly automated process exists. Most outage coordination already takes place through ISO-managed portals because of the convenience, data consistency, and security they provide. Instead of playing to the least-common denominator (i.e.; fully manual outage coordination), IRO-017-1 should be written in a manner that assumes that portals exist – rendering most of the requirements in this standard irrelevant.
No
ICLP believes the changes made to TOP-001-3 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions – not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of TOP-001-3. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business – by far the larger category – must be excluded. TOP-001-4 R1 and R2 provides no limitations on applicable Operating Instructions. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirements R1 and R2 specifically limiting their applicability to a set of defined circumstances. A better method may be to require the TOP or the BA to identify the Operating Instruction as “critical” to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP believes that a qualifier must be added to R3 and R5 for the Operating Instruction recipient to notify the issuer “upon recognition” of its ability to perform it. This language would account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith – but finds out later they cannot. Lastly, ICLP does not agree with the intent and language of Requirement R18. This poorly defined requirement has been transferred from IRO-005 – and has been inconsistently applied by CEAs. R18 leaves it to the GOP to operate to someone’s most “limiting parameter” if there is a conflict with someone else’s “derived limits”. This seems to infer those transmission Facility Ratings, SOLs, or IROLs maintained by the RC and TOP – parameters which GOPs do not monitor. Those difference should be resolved between TOPs and RCs, who then must inform the GOP what the proper limits are.
Yes
No
R1.1 allows the Transmission Operator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new

Definition of the BES. This process was developed precisely for this reason – and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied unevenly across Transmission Operators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R5). The TOP and BA should provide those specifications and processes under Requirements R1 and R2. If there is an issue with the term “mutually agreeable”, the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
Yes
Yes
No
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Xcel Energy agrees with the proposed changes overall. However, we would like to note that R3 requires entities to comply with Operating Instructions given by the TOP, while in R5 they are to comply with instructions of the BA Operator. We would like to see clarification added in the event that the operating instructions from the TOP and BA contradict each other. Additionally, R10 and R11 both reference Special Protection Systems. We would like to ensure this reference syncs up with the efforts of Project 2010-05.2 regarding the SPS/RAS Definition.
Yes
Yes
Yes
Yes
Yes
No
Yes
No
Individual

Anthony Jablonski
ReliabilityFirst
ReliabilityFirst submits the following comments for consideration: 1. Requirement R3 – ReliabilityFirst recommends there be a timeframe be added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform the Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform Operating Instruction in a timely manner. ReliabilityFirst suggests the following for consideration. “Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator [within 30 minutes of receiving an Operating Instruction] of its inability to perform the Operating Instruction…”
No
ReliabilityFirst submits the following comments for consideration: 1. Requirement R7 - The phrase “as necessary” is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. RF suggests removing the phrase “as necessary”, which is vague and creates concerns similar to those expressed by the Commission in Order 791. In Order 791, the Commission supported the RAI’s goal to develop a framework for the ERO Enterprise’s use of discretion in the compliance monitoring and enforcement space, but rejected the codification of “identify, assess, and correct” language within the CIP Version 5 Reliability Standards because it is vague. ReliabilityFirst is also concerned that the qualifier “as necessary” codifies discretion within IRO-008-2. ReliabilityFirst believes that neither discretion nor controls should be codified in Reliability Standards. Rather, the ERO Enterprise should utilize discretion in the compliance monitoring and enforcement space when determining the relevant scope of audits and whether to decline to pursue a noncompliance as a violation. With the RAI, the ERO Enterprise is developing a singular and uniform framework to inform the ERO Enterprise’s use of discretion in the compliance monitoring and enforcement space. Therefore, ReliabilityFirst recommends removing the qualifier “as necessary” from R7 and allow the ongoing RAI effort to create a meaningful and unambiguous framework that the ERO Enterprise will utilize to inform its use of discretion in the compliance monitoring and enforcement of all Reliability Standards. ReliabilityFirst cautions that codifying discretion in some Reliability Standards may create confusion once the ERO Enterprise begins to implement the RAI and its discretion in compliance monitoring and enforcement work. For example, there may be confusion of whether discretion codified in certain Requirements of Reliability Standards precludes the ERO Enterprise’s use of RAI discretion for those Requirements where discretion is not codified. ReliabilityFirst offers the following for consideration: “Each Reliability Coordinator shall issue Operating Instructions, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.”
Yes
ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 – The phrase “as deemed necessary” is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state “... including sub-100 kV but greater than 50 kV data“. This language is consistent with the NERC BES definition, and has a technical justification developed by the that SDT.
Yes
Yes
ReliabilityFirst submits the following comments for consideration: 1. Requirement R4 – The term “coordinate” is ambiguous and unclear and may lead to unintended compliance implications. For example, is coordination satisfied by notice? RF recommends replacing the term “coordinate” with “jointly develop” in order to avoid unintended confusion.
Yes
ReliabilityFirst submits the following comments for consideration: 1. Requirement R4 – ReliabilityFirst recommends there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform the Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. “Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by its Transmission Operator…” 2. Requirement R6 - ReliabilityFirst recommends adding a timeframe to the requirement limiting the time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform an Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by that Balancing Authority.”
Yes
Yes

ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 - The phrase "as deemed necessary" is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state "… including sub-100 kV but greater than 50 kV data". This language is consistent with the NERC BES definition, and has a technical justification developed by that SDT.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
R1 – N/A R2 and R3 – ATC agrees with the proposed IRO-001-4 Requirements R2 and R3.
No
R1 – Although proposed IRO-008-2 is not applicable to ATC, ATC suggests the removal of the word "Wide" from the term "Reliability Coordinator Wide Area" in Requirement R1. "Reliability Coordinator Wide Area" is not currently defined, nor proposed for inclusion in NERC's Glossary of Terms.
Yes
R1, R2 – N/A R3 – ATC agrees with the proposed Requirement R3, however, ATC suggests the requirement be reworded as follows to provide clarity and consistency with currently effective Requirement R3 from Reliability Standard IRO-010-1a: "R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator,Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications, to the Reliability Coordinator with which it has a reliability relationship, using a mutually agreeable:" 3.1 Format 3.2 Process for resolving data conflicts 3.3 Security protocol"
No
ATC requests that the SDT consider making the following modifications: a. R1 - N/A b. R2 – ATC agrees with the proposed IRO-017-1 Requirement R2. c. R3 – To provide more specificity and flexibility, ATC suggests Requirement R3 be reworded as: "R3. Each Planning Coordinator and Transmission Planner shall make each new Planning Assessment available to impacted Reliability Coordinators and their Transmission Operator(s)." The revised language clearly indicates which Planning Assessment is provided and when. In addition, the language allows PCs and TPs to make a web-based version of the Planning Assessment and not require conversion of the Assessment to a form that can be transmitted to applicable Reliability Coordinators by mail or email. Finally, ATC suggests that Transmission Operators be added as an applicable entity for receipt of the Assessment. d. R4 –ATC suggests removal of the proposed Requirement R4 entirely. The rationale is that the Reliability Coordinator should not have to resolve potential planned outage conflicts more than one year out with the Planning Coordinator and Transmission Planner. There are too many variables on this time scale that affect the answer. A better approach would be for the RC, TOP(s) and GOP(s) to resolve any outage conflicts, including moving or cancelling the outage, once the time window is within the "one year out" timeframe.
No
ATC requests that the SDT consider the following recommended modifications: a. Real-time Assessment definition - ATC suggests the definition be reworded as follows for added clarity. "An evaluation of system conditions using Real-time data to assess contingency conditions, limited to the single Contingency loss of a generator, line, transformer or shunt device and multiple outages as specified by its RC, to assess potential operating conditions." Otherwise, ATC suggests the following changes to the definition: Modify the first sentence of the definition by adding the word "single" to read, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) operating conditions." Otherwise, ATC suggests adding a sentence to the proposed definition to read, "Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator." b. R1 – For clarity, ATC recommends that Requirement R1 be modified to define "others" as "DP(s), LSE(s), BA(s) and GOP(s)." c R2, R11, R17 - N/A d. R3 – ATC agrees with the proposed TOP-001-3 Requirement R3. e. R4 – ATC agrees with the proposed TOP-001-3 Requirement R4. f. R5 – ATC agrees with the proposed TOP-001-3 Requirement R5. g. R6 – ATC agrees with the proposed TOP-001-3 Requirement R6. h. R7 – ATC agrees with the proposed TOP-001-3 Requirement R7. i. R8 – ATC has no comment regarding Requirement R8. j. R9 – Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their contingency analysis capabilities after the functionality is lost. Therefore, ATC

recommends the requirement should be revised as follows to only address forced or unexpected outages. "R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." k. R10 – ATC sees Requirement R10 as ambiguous regarding what is being monitored. It is unclear if the TOP is to monitor topology changes, analog values for violation, and/or model neighboring TOP contingencies in its Real-time Assessments for the neighboring TOP system. In addition, the current wording does not clearly state which sub-100 kV facilities are to be monitored (i.e., its TOP area or the neighboring TOP area). ATC recommends splitting the requirement into two parts to address these issues. ATC recommends rewording Requirement R10 as follows: "R10. Each Transmission Operator shall monitor BES Facilities and the status of Special Protection Systems within its Transmission Operator Area needed to maintain reliability within its Transmission Operator Area, including non-BES Facilities needed to maintain reliability." l. ATC recommends Requirement R10.1 be addedprepared as follows: "R10.1. Each TOP shall monitor system topology changes within neighboring Transmission Operator Areas, including non-BES Facilities, to maintain reliability within its Transmission Operator Area." m. R12 – ATC agrees with the proposed TOP-001-3 Requirement R12. n. R13 – ATC provides the following suggestions regarding Requirement R13. Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore, it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains the requirement, ATC recommends developing a performance-based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example – CPS1 / CPS2 BA performance metrics. o. R14 – If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, ATC feels that the language in Requirement R14 shwould be improved modified by removing some redundancy and adding clarity. ATC suggests the removal of "Real-time monitoring" from the proposed requirement since the "Real-time Assessment" definition already requires assessing existing operating conditions. In addition, ATC suggests the addition of "within its Transmission Operator Area" to R14 to provide clarity and be consistent with the language proposed for TOP-002-4. ATC suggests the language of Requirement R14 read as follows: "R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance within its Transmission Operator Area identified as part of its Real-time Assessment." p. R15 - ATC agrees with the proposed TOP-001-3 Requirement R15. However, ATC suggests development of a similar requirement applicable to Interconnection Reliability Operating Limits (IROLs). q. R16 – If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, the language in Requirement R16 should be modified by removing some redundancy and adding clarity. ATC suggests the removal of "monitoring" from the proposed Requirement R14 since the "Real-time Assessment" definition already requires assessing existing operating conditions. ATC also suggests the addition of "within its Transmission Operator Area" to R16 for added clarity. ATC suggests the requirement be reworded as: "R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own Real-time Assessment capabilities within its Transmission Operator Area." r. R18 – To improve clarity and be consistent with proposed definitions, ATC suggests revising Requirement R18 by replacing the term "derived operating limits" as indicated in the following revision of the requirement: "R18. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting real-time (pre-Contingency) or potential (post-Contingency) operating condition in instances where there is a difference in SOLs or Real-time Assessments."
No
ATC requests that the SDT consider the following recommended modifications: a. To be consistent in regards to terminology used in the Standards, ATC suggests that "Operational Planning Analysis" be renamed "Operational Planning Assessment" similar to the term "Real-time Assessment." For consistency, ATC suggests that this change be made throughout the proposed draft of Standard TOP-002-4. b. Operational Planning Analysis definition - ATC suggests the following changes to the definition for added clarity. Modify the first sentence of the definition by adding the word "single" to read, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) for next-day operations." Otherwise, ATC suggests adding a sentence to the proposed definition to read, "Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator." c. ATC requests the SDT to clarify the inconsistency between the use of "Operating Plan" in requirements R2 and R3 of TOP-002-4 with the explanation of this term in the "Rationale for Requirement R14" box within the draft TOP-001-3 standard. Specifically, the "Rationale for Requirement R14" explanation states that the "Operating Plan" is a single, general plan and philosophy for dealing with SOL exceedances. However, R2 and R3 of TOP-002-4 refer to the "Operating Plan" as a specific SOL exceedance plan with clearly identified actions by specific NERC registered entities. It is unclear if the TOP is to understand that the Operating Plan is a general philosophy or specific individual plans for each SOL exceedance identified during the next-day assessment. The companion white paper will not be part of the standard so clarity within the standards is important.
No
ATC requests that the SDT consider the following recommended modifications: a. R1, R1.1, and R3 – See comments submitted under TOP-001-3 (Question #7) regarding proposed changes to the definition of "Real-time Assessment". If

ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, to eliminate redundant wording related to Real-time requirements, ATC suggests the term "Real-time monitoring" be removed from Requirements R1, R1.1, and R3 since the "Real-time Assessment" definition shown in draft Standard TOP-001-3 already requires assessing existing operating conditions. b. R1.1 – To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.1 be modified by replacing "as deemed necessary by the Transmission Operator" with "needed to maintain reliability within its Transmission Operator Area." c. R1.2 – To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing "that impacts System reliability" with "needed to maintain reliability within its Transmission Operator Area." d. R1.2 – To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing "that impacts System reliability" with "needed to maintain reliability within its Transmission Operator Area." e. R2 – To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2 be modified by replacing "perform its analysis functions and Real-time monitoring" with "perform its reliability functions." f. R2.1 – To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.1 be modified by replacing "perform its analysis functions and Real-time monitoring" with "perform its reliability functions." g. R2.2 – To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.2 be modified by replacing "that impacts System reliability" with "impacts generation or Load." h. R4 – To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R4 be modified by replacing "analysis functions and Real-time monitoring" with "reliability functions."
Yes
ATC agrees with the retirement of the Requirements of the noted IRO Standards applicable to its registered functions as identified on the Mapping Document.
Yes
ATC agrees with the retirement of the Requirements of the noted TOP Standards applicable to its registered functions as identified on the Mapping Document.
Yes
ATC has no comment whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators.
No
No
Group
SERC OC Review Group
Stuart Goza
Yes
The SERC OC Review Group requests clarification on who "others" are for R1: "RC shall act, or direct others to act," Suggestion: "directs others (as identified in R2) to act". Current: "Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area." Suggested: "Each Reliability Coordinator shall act, or direct others (as identified in R2) to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area."
No
The SERC OC Review Group has concerns adding TP, PC, and DP to real-time data requirements to R2. DP provides info to TOP who then provides info to RC. Neither the TP nor PC provides the RC real time data, thus not requiring a data connection.
No
1) In R6, the wording does not reflect the changes in the rationale. 'Exceedance' has not been replaced with 'emergency'. Did this change occur as result of multiple revisions in the draft? Current: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area." Suggested: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) emergency within its Reliability Coordinator Wide Area." 2) In the R5 VSLs, there is concern that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Suggestion: expand bandwidth. 3) In R8, replace "prevented or mitigated" with "addressed". Current: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System

Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.” Suggested: “Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been addressed.”
Yes
1) The proposed R1.7 in the rationale is not listed in the document. 2) For the entity receiving a data request, it is preferred some language to be added that allows the entity supplying the data to coordinate the request to ensure a sufficient reliability need. Possible language as used in MOD- 001-02, R5 “Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall…”
No
In R4, recommend replacing “other” with “adjacent” and removing part of sentence “within the same interconnection.” Current: “Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection.” Suggested: “Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with adjacent Reliability Coordinators.”
Yes
No
1)Request clarification on who “others” are for R1 & R2, “RC shall act, or direct others to act,”. Suggestion: “directs others (as identified in R3) to act”. Current: “shall act, or direct others…” Suggested: “shall act, or direct others (as identified in R3)…” 2) R7 is missing the use of the word “effective” that was referenced in the rationale. 3) In R9, remove “and negatively impacted interconnected NERC registered entities” because each entity does not always know who may be impacted. (i.e. entity in SERC is providing data to NYISO. Is NYISO an impacted entity for loss of the data?) Also, insert ‘planned’ before outages in Requirement to be consistent with M9 and the VSL for R9. Current: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” Suggested: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” 4) In the R13 VSLs, there is concern that the bandwidth between “lower” and “severe” VSL is only 15 minutes. Suggestion: expand bandwidth. See also response on IRO-008-2, question 3 above.
Yes
In R3, M3, R5, & M5 a suggestion to change wording from “notify” to “coordinate”. Suggested wording in R3, R5: “shall coordinate with NERC registered entities identified in the Operating Plan(s)” instead of “shall notify impacted NERC registered entities”. Suggested wording in M3, M5: “shall have evidence that it coordinated impacted”.
Yes
1) In R3 & R4, insert term ‘NERC registered’ before ‘entities’. Due to temperature readings being obtained from the National Weather Service (NWS), some may consider the NWS to be an entity requiring the data specifications. Current: “Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.” Suggested: “Each Transmission Operator shall distribute its data specification to NERC registered entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.” 2)Suggestion to add “R5.4 A mutually agreeable reliability need” 3)In R5, for the entity receiving a data request, it would be preferred that some language is added to allow them to coordinate the request to ensure a sufficient reliability need. See response to Question 4 above.
Yes
Yes
No
No
IRO-001-13, R1.3, IRO-008-2 R5. The SERC OC Review Group has concerns that the bandwidth between “lower” and “severe” VSL is only 15 minutes. Low 30 minutes, high VSL 45 minutes) Suggestion: expand bandwidth.
No

Individual
Thomas Foltz
American Electric Power
No
R8: Needs additional clarity and consistency with other requirements. A TOP is able to communicate any emergencies they see/foresee in their system and communicate these issues to the RC and entities known to be directly-impacted. The RC would have the wide-area view necessary to determine any impacts to other BAs or TOPs. However, a TOP would have limited ability to know if they're creating any impact regarding other BAs or TOPs that aren't interconnected with them. The standard should be changed to require the RC, not the TOP, provide such communication. R9: The requirement needs to specify which "negatively impacted interconnected NERC registered entities" need to be notified in order to be consistent with R8 and other requirements. R10: It is not clear exactly which sub-100 KV Facilities need to be monitored by the TOP. In addition, the TOP is in the best position to make this determination. The requirement should be changed to allow the TOP flexibility to identify which facilities are to be monitored.
No
R3: If a NERC registered entity is included in an Operating Plan, there is no need to use the word "impacted" as it could add confusion. This word should be removed.
No
Please provide reasoning for the removal all references to the NERC Confidentiality Agreement from TOP-005-2. R1: How detailed would the data specifications need to be, especially in regards to data between other entities, in order to satisfy the requirement? R3: For data taken from NERC SDX, how would a data specification be sent? There is an established process in SDX for sharing data, and this proposed standard does not align with it. R5: This does not align with current practices of going through the RC for transferring operational data between NERC entities. R5.3: The phrase "Mutually agreeable security protocol" is vague and is subjective due to its potential interpretation by various entities and regions.
Yes
AEP's negative vote on TOP-002-4 is solely driven by the proposed definition on which it relies, not on the direction or intent of the standard itself. Comments regarding proposed definitions: Operating Planning Analysis: "Identified phase angle…limitations" needs to be clarified. The definition could be interpreted as requiring either a) continual analysis of all phase angles or b) analysis of pre-determined phase angle limitations at specific locations. AEP believes the definition should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. In the event continual analysis is required, what determines the placement and number of measurements for a given system? In that case, the definition should clarify that if phase angle is considered in the study, and if a phase angle limitation is identified, than that limitation should be included in the analysis. Rather, AEP proposes the following definition: " An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation should reflect inputs such as (but not limited to): load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)" Real-time Assessment: Once again, AEP has concerns similar those expressed for the definition of Operating Planning Analysis , as the definition for Real-time Assessment should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. We propose the following definition: "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment should reflect inputs such as (but not limited to): load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)"
Individual

David Austin
NIPSCO
No
1. In R5 the term “highly” reliable is used. Please define “highly”. 2. In R2 “data links” needs to be defined, as well as the context in which they are to be used (what are the data links for?). 3. Should R1 and R2 be contained in the COM standards, as opposed to IRO-002? 4. R3 should be included in IRO-017, as it is an outage coordination requirement.
No
1. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard. 2. In R8 NIPSCO would like the term “emergency” defined. Is an “emergency” the same as a SOL exceedance or is it a SOL or IROL violation? 3. R10 requires that TOPs monitor adjacent TOP facilities as “needed to maintain reliability.” This term is vague and needs defined parameters or criteria. 4. The data retention period for R13 is far too long, as the RTCA files are quite large (current calendar year + previous calendar year).
No
The data retention period required for the analysis is a rolling (6) months, as opposed to the prior data retention period of 90 days (TOP-002 R11). This time frame is too long and needs to be revisited unless there is a valid concern for holding 6 months of analysis.
Yes
NIPSCO has the following comments about the new Definitions: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. 2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
No
Although the SDT’s Rationale indicates there is no redundancy with proposed requirements in this Project 2014-03, Southern believes Requirements 1 and 2 are redundant with existing effective COM-001-1 R1 and future mapping of this requirement to future enforceable standards. Southern also notes that COM-002-2 R1 is the corresponding requirement for the TOPs and BAs to have both voice and data links with appropriate RCs, BAs, and TOPs. Southern suggests that these existing standards and other industry approved future enforceable standards addresses any reliability gaps. Southern also suggests that R2 is redundant with both the existing and proposed IRO-010 in this project. IRO-010 already requires the RC to provide data specifications to the entities listed in R2 and requires such entities to provide the data specified by the RC. Southern recommends that both R1 and R2 be removed. As an alternative to removing R2, Southern suggests that TPs/PCs be removed from R2 because these functional entities were specifically added to IRO-010 for purposes of providing UFLS and UVLS data to RCs. They do not need to be in both standards. The proposed Requirement 3 needs to be revised to clarify that it is only addressing monitoring and analysis capabilities and not planned outages and maintenance of BES elements. As currently drafted, one could interpret it as planned outages of BES element and maintenance of monitoring and analysis capabilities, and Southern does not think that is the intent of the SDT. Southern suggest changing the requirement to, “Each Reliability Coordinator shall provide its System Operators with the authority to approve the following: R3.1. planned outages of its

monitoring and analysis capabilities. R3.2. maintenance of its monitoring and analysis capabilities. Requirement 4, as proposed, does not indicate how far into the neighboring system a RC should monitor. Southern suggest incorporating language referencing the RCs wide area view methodology and language specifying that it should include sub-100 kV facilities, “as deemed necessary by the RC” (similar to the language used in the proposed IRO-010-2 R1.1). Southern proposes the following verbiage to add clarity to the requirement: “Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas consistent with its wide-area view methodology to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area , including sub-100 kV facilities, as deemed necessary by the Reliability Coordinator, and the status of Special Protection Systems, to make this determination."
No
By the various uses of “Operating Plan” in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? Southern believes IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded as it will require RCs to produce an email response to all TOP and BA operating plans stating “reviewed”. RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, Southern recommends removing requirement R2. As mentioned above, the use of Operating Plan in R6 is confusing. Does the SDT consider this to be a single continuously updated Operating Plan or does the SDT expect this to have been an Operating Plan developed for next day assumptions which then transitions into a different Operating Plan when a real time condition is observed? Also, as currently drafted, R6 is very confusing. Southern proposes rewording R6 to move the “as indicated in its Operating Plan” statement to the end to add clarity and eliminate confusion. “Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area as indicated in its Operating Plan.” For R7 and R8, consider the example where the RC and a TOP see a potential SOL in their real time assessments and coordinate with one another on a post contingency plan to address the issue. As time passes and system conditions change, the contingency issue no longer exists. These requirements create an administrative burden on RCs to notify the TOP if the contingency issue has subsided without ever having to implement a plan. A more realistic requirement would be for the RC to notify the TOPs/BAs that are having to reconfigure their system or redispatch generation to resolve an SOL issue when the SOL has been prevented or mitigated. Southern suggests rewording R7 and R8 to remove the administrative burden of notifications when no action was taken by a TOP/BA.
Yes
Should proposed Requirement 1.2 be included in IRO-010-2 or in a PRC requirement? Southern believes that the SDT should consider if this requirement is better suited for PRC standards. The previous version included Requirement 1.4: “Process for data provision when automated Real-Time system operating data is unavailable.” It is unclear why the SDT removed this sub part from the proposed IRO-010. Please provide the SDT’s rationale for removing because there are times with the automated methods of providing data are unavailable.
Yes
No
Overall, Southern does not agree with this new outage coordination standard. This standard is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary, which is current day and next day operations. As written, this requirement conflicts with the Functional Model and the NERC Glossary, which both clearly address the roles of the Reliability Coordinator. The Reliability Coordinator, according to the Functional Model, “receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.” Furthermore, the NERC Glossary notes that the Reliability Coordinator “is to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.” This definition indicates that the Reliability Coordinator’s scope is for next day and real-time operations. Southern recommends that this standard be withdrawn from the project. If the SDT does not withdraw the standard, at a minimum, the SDT should modify the standard to address the following comments. The proposed subpart 1.5 requires RCs to document and maintain the specifications for outage analysis during the operations planning horizon, which is next day to one year out. We do recognize that the SDT’s rationale provides the RCs with some discretion as to whether or not the RC desires to have specifications for outage analysis in the operations planning horizon; however Southern recommends adding language to subpart 1.5 to clearly state that the RC has discretion by adding “, if deemed necessary by the RC” to the end. Southern does not agree with R4 as it seems to imply that RCs conduct outage coordination assessments even beyond the operations planning horizon. Again, RCs are focused on real time and next day timeframes, not the Planning Assessment timeframe, and should not be required to coordinate solutions in the Planning Assessment timeframe. This requirement is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary (see definition of RC), which is current day and next day operations. This requirement should be removed, or, at a minimum, be revised to include “if deemed necessary by

the RC". The existing TOP-002-2.1b R11 requires TOPs to perform seasonal studies to determine SOLs and to provide the results of those studies to its RC.
No
R1 and R2 – Southern suggest that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 – The Rationale section for Requirement R7 states that the word 'Emergency' was deleted and the word 'Effective' was added to the Requirement language. The word 'Effective' is missing from the Requirement language. R8 – Southern suggests that the phrase 'could result in' is too open ended and assumes that operations takes place as expected and does not account for failures and equipment during the operations such as faulted breaker, or human performance errors. R9 – Add the word 'planned' to Requirement language to match Measure language. R9 – The phrase 'negatively impacted Interconnected NERC registered entities' seems broadly generic. Southern suggests adding the words, 'other affected adjacent BAs and TOPs'. Suggested Requirement language: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and other affected adjacent BAs and TOPs, of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Suggested Measure language: M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and other affected adjacent BAs and TOPs, of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation. R10 – Southern recommends adding the words 'as deemed necessary by the TOP' after the words sub-100 kV facilities which would make this TOP requirement consistent with the corresponding RC Requirement in IRO-008. Suggested Requirement language: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities, as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area. Suggested Measure language: M10. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area . R11 – Southern suggests that the SDT coordinate with the SPS drafting team on the use of RAS versus SPS for Requirement R11 as well as throughout the standards included in this project. R14 – Southern suggest deleting the phrase, 'as part of', and adding 'as a result of'…. Suggested Requirement language: R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedanceidentified as a result of its Real-time monitoring or Real-time Assessment. Suggested Measure language: M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as a result of its Real-time monitoring or Real-time Assessments. This evidence could include, but is not limited to, dated computer logs showing time the Operating Plan was initiated, dated checklists, or other evidence. R15 –Southern suggest that R15 as written has the potential for adding to Reliability Risk as it could cause the operator to spend time notifying the RC for compliance reasons rather than responding to the SOL exceedance. Instead, we suggest the requirement be re-written to have the TOP inform its RC of its inability to return the system to within limits when an SOL has been exceeded. Suggested Requirement language: R15. Each Transmission Operator shall inform its Reliability Coordinator of its inability to return the system to within limits when an SOL has been exceeded. Suggested Measure language: M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of its inability to return the system to within limits when an SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recording, or dated computer printouts. R16 and R17 – These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 – These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 – There is confusion in the Industry of what the current term 'derived limits' means. The SDT should take this opportunity to clarify whether 'derived limits' is referring to SOLs, IROLs. If this is the case, then why use the term, 'derived limits'?
No
R4 – Southern suggests that sub requirements, 4.1, 4.2, 4.3 and 4.4 are vague in nature and should be more descriptive by defining specific expectations of what should be addressed. Example: R4.2 as written is unclear as to whether the BAs Operating Plan is expected to address making, accommodating, curtailing, ramping of interchange schedules, etc. R4 and R5 and R7 – It is unclear on what actions would be included in the BA Operating Plan. In the case of the TOP, it is very clear in that the Operating Plan is to address potential SOLs. The R4 subparts include data provided to the BA for reserves planning purposes from other entities. The BA should not be required to notify all

entities and provide them with the very information those entities provided to the BA as seems to be required in R5. R6 and R7 – Southern suggest that a periodicity for providing data and a deadline by which the respondent is to provide the indicated data should be applied to these requirements to be consistent with corresponding RC requirements, R1.3 and R1.4 in proposed IRO-010-2 Reliability Coordinator Data Specification and Collection.
Yes
The word 'Coordinator' should be added after the word 'Reliability' in the last sentence of the Rationale paragraph for R1. Southern suggest adding the words, 'NERC registered' after the word 'to' in requirement's 3 & 4 and Measures 3 & 4, and adding the phrase, 'a reliability-related need for', after the words, 'that have' in requirement's 3 & 4 and Measures 3 & 4. Suggested Requirement language: R3. Each Transmission Operator shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time assessment. R4. Each Balancing Authority shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority's analysis functions and Real-time monitoring. Suggested Measure language: M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records. M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.
Yes
Yes
No comments
No
No
No
Group
Dominion
Louis Slade
No
Dominion does not agree with requirement 1 as it is very similar to COM-001-2, R1 and because we do not agree that the Reliability Coordinator should be required to have direct communications facilities with Generator Operators within its Reliability Coordinator Area. We believe that the Interpersonal Communication capability developed pursuant to COM-001-2 could allow the Reliability Coordinator to communicate to Balancing Authorities or Transmission Operators in its Reliability Area, and requiring that entity to communicate directly with other operators and users (including DP, GOP and LSE). Dominion does not agree with requirement 2 as written. While we agree that each Reliability Coordinator should have data links with each Balancing Authority and Transmission Operator within its reliability area and with neighboring Reliability Coordinators, we do not agree that it should be required to have data links with all Generator Owners, Generator Operators, Load-Serving Entities Transmission Owners, and Distribution Providers in its reliability area. We believe this requirement should NOT apply if the Reliability Coordinator's documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (pursuant to Proposed IRO-010-2, Requirements R1 and R3, part 3.3) allows for the data to be provided via data links with a Balancing Authority or Transmission Operator within its reliability area. We can agree that data links with Planning Coordinators or Transmission Planners be required only if the Reliability Coordinator identifies the need for data pursuant to IRO-010-2. Dominion does not see the need for Requirement 3. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We would prefer to modify the requirement to read "Each Reliability Coordinator shall monitor BES Facilities, and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." It is our position that any relevant sub-

100 kV facility should be included as a BES Facility through the BES Exception process. 2nd citing of R4 in the mapping document Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We would prefer to modify the requirement to read “Each Reliability Coordinator shall monitor BES Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area and the status of Special Protection Systems in its Reliability Coordinator Area.” It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process.
Yes
No
Dominion does not agree with the purpose statement as written. It infers that ensuring the RC has data necessary to monitor and assess the operation of its Reliability Coordinator Area will somehow prevent instability, uncontrolled separation, or Cascading outages. Dominion suggests revising similar to “To ensure the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.” Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline.
No
Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion finds R1.5 to be administrative in nature and therefore do not support inclusion of this sub-requirement. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion finds R1.6 to be administrative in nature and therefore do not support inclusion of this sub-requirement. While Dominion agrees that each Reliability Coordinator should be required to participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum requirement. Dominion finds R4 to be administrative in nature and therefore do not support inclusion of this requirement. While Dominion agrees that each Reliability Coordinator should participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum (such as weekly) requirement. We could support if the phrase “at least weekly (per Requirement R1, Part 1.6)” were removed. Dominion does not agree with use of the term Emergency in requirements 5 through 8. Part of the definition of the term includes the phrase “Any abnormal system condition that requires automatic or immediate manual action…”. We do not believe that the intent of Standard IRO-016-1@R1 was to wait until immediate action was necessary for the Reliability Coordinator to notify other Reliability Coordinators. We believe the intent was to make notification upon recognition of conditions that indicate a potential, expected, or actual problem. We could support if the words potential or expected were used in conjunction with the term Emergency. Alternatively, we could support language similar to that used in TOP-001-3, Requirement 8.
No
Dominion does not believe that sub-requirement 1.5 allows the Reliability Coordinator to request seasonal planning assessments if so desired. Instead it appears to require they do so. We suggest revising to read “Document and maintain the specifications for outage analysis during the operations planning horizon if desired.”
No
While Dominion agrees conceptually with Requirements 5 and 6 we do not believe they belong in the TOP family of standards. Dominion does not agree with Requirement 7 as we do not see how it is substantially different from R3 and R5 under this standard and we expect that, in many cases, such assistance is likely to come in the form or an Operating Instruction issued by a Reliability Coordinator, in which case the recipient must comply. We oppose because this requirement does nothing to increase reliability; it only increases compliance risk for the entity. Dominion does not agree with R10 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We could support if revised as indicated “Each Transmission Operator shall monitor BES Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area and the status of Special Protection Systems within its Transmission Operator Area.” It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion has concerns with inclusion of Generator Operator in Requirement 18. The only limits the GOP is aware of are those for the facility it operates. The GOP is not typically provided limits or ratings for facilities it does not operate and, where it is provided such, it has only that single value and therefore no derived difference can be determined. For these reasons, we suggest Generator Operator be deleted from this requirement.
No
While Dominion agrees conceptually with Requirements 4 and 5 we do not believe they belong in the TOP family of standards.
No

Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion does not see a distinct difference between sub-requirements 2.3 and 2.4. We believe that periodicity infers the deadline.
Yes
Yes
Dominion believes that Tthe required periodicity for the performance of Real-time Assessments should be at least once every ten minutes. This is the periodicity that NERC required MISO and First Energy to meet following the August 14, 2003 blackout. See page 152 of the Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004
Yes
Dominion would like to state its support and agreement with this well written paper.
Individual
Dave Willis
Idaho Power
No
N/A
No
I agree with the revisions to IRO-10-2 but have concerns with requirement 3. If the RC is willing to provide attestation that the requirement has been fulfilled it will be no problem. If the entity is required to provide evidence it will be more difficult. You could retain all the emails but how do you prove that was all the requests.
Yes
I don’t have any great concerns with IRO-017-1 but R1 seems a little vague. Depending on the process that the RC establishes this could become quite onerous, it would be better if more of the outage coordination process was defined in the standard itself rather than leaving it entirely up to the RC.
No
I do not agree with the rationale for the change in terms. There need to be something to differentiate between a communications that must be followed to alleviate existing or potential conditions to preserve system reliability. Operating instructions should be normal communication between a System Operator and field personnel during routine switching or system adjustments. A Reliability Directive is an order to do a task without hesitation unless it would violate safety, equipment, regulatory or statutory requirements. As currently written the standard would seem to apply to anything the RC requested a TOP to do. Reliability Directive is in the NERC glossary of terms currently. The first sentence in R1 notes this when it states "or DIRECTS others". This change will create confusion resulting in adverse reliability impacts and compliance violations. I’m not clear on what R10 requires. Would we be required to monitor all our adjacent TOP’s SPS and communication systems, facilities that the SPS monitored or just request a status point via ICCP form the adjacent? Needs to be clearer on what the requirement expects to be monitored.
No
I do not agree with this standard as written. The definition of Operational Planning Analysis would seem to require a TOP to have or contract Real-Time Contingency Analysis (RTCA) and all the required inputs. The definition does not specify what area should be modeled. It would seem that an entity could only model their internal system with their local inputs and be in compliance with this standard. If you are going to mandate RTCA the there should be some expectation that external systems be modeled to some extent to better reflect actual conditions. As shown in the Southwest outage only looking at the extents of your system is not adequate.
Yes
I do not have a problem with TOP-003-3 but feel it should be conbined with IRO-010-2 as the requirements are basically the same only the applicability is differnent.
Yes
I do not have a problem with TOP-003-3 but feel it should be combined with IRO-010-2 as the requirements are basically the same only the applicability is different. Combining the two standards would be best. The best solution

would be to have a clearing house for all the data. The BA would submit the data to the RC on behalf of the TOP & GOP and it would be available for all other BA's.
The 30 minute time seems to be an arbitrary value. Real-time Assessments need to be done as system conditions change; load or interchange changed by XXX MW's or system topology changes would seem to be a more logical trigger. That said a specific time frame of 30 minutes, 45 minutes or 1 hour would be easier to audit. Inaccurate assessments that have been rushed in order to meet a compliance standard can have extreme adverse impact on reliability.
No
No
No
Group
Florida Municipal Power Agency
Carol Chinn
No
FMPA supports the comments of FRCC Operating Committee (Member Services).
No
FMPA supports the comments of FRCC Operating Committee (Member Services).
No
FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify "in accordance with its SOL Methodology" so that the breadth of contingencies to be studied is known.
No
FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, R1 should specify a "minimum" set of data requirements. This is especially apparent when protection system status is called out in 1.2, but the status of the Facilities being protected is not called out – which is more important to reliability? Due to the ambiguity of what is and is not included in R1, other SDTs for other standards were unwilling to accept that there is duplication (see comments to TOP-003 R1 and R2 for more detail). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards. As such, we propose the SDT develop a "minimum" set of data, notification, information, etc., requirements as an attachment to the standard. RCs can always specify more if so desired.
No
FMPA supports the comments of FRCC Operating Committee (Member Services).
No
FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes seasonal analyses to evaluate planned maintenance is an important reliability function that should not be lost and cannot be replaced by "Planning Assessments". Recommend modifying R1.5 as follows: "Specify a periodicity, not less frequently than seasonally, of outage analyses during the operations planning horizon."
No
FMPA supports the comments of FRCC Operating Committee (Member Services). Also, GOPs do not need to be listed in R18 since their role in operating to the most limiting parameter is to follow the directives of the TOP and BA.
No
FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify "in accordance with its SOL Methodology" so that the breadth of contingencies to be studied is known
No
FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, R1 and R2 should specify a "minimum" set of data requirements. This is especially apparent when protection system status is called out in 1.2 and 2.2, but the status of the Facilities being protected is not called out – which is more important to reliability? Due to the ambiguity of what is and is not included in R1 and R2, other SDTs for other standards were unwilling to accept that there is duplication (e.g., VAR-002, which was just revised, requires notification of voltage regulator status, and information about GSUs and tap settings, items which should also be included in the data specification). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 and R2 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards.

As such, we propose the SDT develop a “minimum” set of data, notification, information, etc., requirements as an attachment to the standard. TOPs and BAs can always specify more if so desired. In R5, what data is needed from the IA that is not provided by the BA? Likewise, all of the data needed from an LSE can also be provided by the DP (i.e., load forecasts). As a result, FMPA recommends eliminating IA and LSE from the requirement.
Yes
Yes
FMPA agrees with 30 minutes as a minimum periodicity for Real-time Assessments.
No
FMPA supports the comments of FRCC Operating Committee (Member Services).
Individual
Laurie Williams
PNMR
Yes
Yes
Yes
Yes
No
IRO-014-1 R3 requires the PC and TP to provide its Planning Assessment to the RC. The rationale states that a summary of the TPL-001-4 assumptions and results would satisfy this requirement. Including this requirement in the IRO is mixing the Operations and Planning Horizons. The drafting team should remove this requirement from IRO-014-1 and recommend that TPL-001-4 R8 be updated to include the RC.
Yes
Yes
Yes
Yes
Yes
Yes
Figure 2 of the whitepaper depicts a PV plot and is used to demonstrate the definition of an IROL. PNMR finds this figure to be confusing. The figure defines the IROL as the “knee” on the PV plot. In WECC the path SOL may be a value less than the “knee” of a PV curve. Does the figure imply that all voltage stability SOLs also have a IROL? Can only path voltage stability and voltage SOLs have IROLs? PNMR would recommend clarifications be added to the whitepaper to resolve these questions.
Yes
No
Individual
David Kiguel
n/a

Yes
No
R1: The requirement of voice comunications facilities is a matter to be addressed by COM standards. Inclusion in IRO-002-4 could introduce compliance issues (double jeopardy). R4: Requires RC to monitor facilities in neighboring Reliability Coordinator Areas i.e. outside of its own.
No
R4: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.
Yes
No
R9: How will the RC that requested assistance demonstrate and how will the RC whose assistance was requested verify that the requesting entity has implemented its emergency procedures?
Yes
No
R7: How will the entity that requested assistance demontrate and how will the entity whose assistance was requested verify that the requesting entity has implemented its emergency procedures? R10: Requires TOP to monitor facilities in neighbouring TOP Areas, i.e. outside its own area of responsibility. R11: How will the BA monitor SPS status i.e. who provides the information? Better to assign requirement action to the entity providing the information to the BA. This seems to be covered by TOP-003-3 R4, i.e. no need to repeat here.
No
R3 and R5: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.
Yes
Yes
Yes
Yes
Agree with the 30 minutes periodicity.
Yes
Intent is correct. Could better explain some concepts like for example when short time ratings could be exceeded in pre-contingency.
No
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Catherine Wesley
PJM Interconnection
Yes
No
Specific to R2, PJM does not agree there needs to be data link requirements between the RC and the PC, TP, LSE and DP to monitor and control the electric system in real-time. Both the TP and PC do not have the real-time data necessary to monitor the system, and therefore, data links are not needed. Specific to the LSE and DP, their real-time data is provided directly to their TOP or TO.
No
Please see PJM’s comments included in Question #12.

Yes
Yes
Yes
Yes
PJM does support the standard. We recommend the drafting team use only the term, 'Facility Rating' and not use the term 'derived limit.' This will provide for consistency is use of one term.
Yes
Yes
Yes
Yes
Yes
PJM supports the 30 minute periodicity. Specific to IRO-008-2, R5, PJM is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. PJM recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
No
Yes
PJM recommends that the drafting team review the requirements in the TOP standards which are applicable to the BA and in which the GO is performing a specific requirement. PJM suggests these requirements be reviewed and moved to the appropriate BAL standards, if they are determined to still be necessary.
Group
Duke Energy
Michael Lowman
No
Duke Energy is concerned that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the RC "act" to ensure the reliability of its RC area is not only a requirement that the RC do its job for which other requirements are applicable, but also a requirement that could be interpreted to require the RC "act" to cover the full scope of any related RC reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirement should focus strictly on the communication desired when needed to ensure the reliability of the RC area. The definition of Operating Instruction makes these requirements (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R1: Duke Energy suggests re-writing R1 as follows: "Each Reliability Coordinator shall issue Reliability Directives, as necessary, to ensure the reliability of its Reliability Coordinator Area." As written, the language requires the RC to act to ensure the reliability if its area, which is similar to writing a requirement that the RC comply with all other RC requirements. The suggested language addresses that point and would eliminate the ambiguity that currently exists in the proposal that an RC must issue an Operating Instruction for all communications, and not when actually warranted. As written, this requirement could be interpreted to suggest that an RC would be non-compliant if at any time they did not issue an Operating Instruction notwithstanding system conditions. In any communication, the RC has the authority to issue a Reliability Directive whenever the circumstances warrant such authority. Also, we would like to add that the RC's responsibilities outlined in R1 are inherent to the NERC Functional Model. Ultimately, we question the necessity of the proposed R1. R2: Duke Energy questions the addition of the TSP into the proposed R2. This requirement references compliance by an applicable entity to an RC's Operating Instruction. An Operating Instruction is considered to be an action that takes place during Real-time operations. Per the NERC Functional Model, the relationship between the RC and the TSP is considered "Ahead of Time" in nature. Additionally, the Functional Model does not provide that an RC may actually direct a TSP to act, only that an RC may coordinate with a TSP on transmission system limitations. As with our prior comment, we believe this requirement should be applicable those receiving Reliability Directives. R3: See our comment above

regarding the relationship between the RC and the TSP above. Also, there appears to be an improper reference to R2 in this requirement. We believe the SDT meant to reference R1 instead, due to the actual issuance of an Operating Instruction from the RC takes place in R1, and not R2.
No
R1: (1) Duke Energy believes that this requirement is duplicative with the currently enforced COM-001-1.1 and the future COM-001-2 and suggest removing this requirement or clarify the need to have this requirement in conjunction with the COM-001 requirements. (2) Per the Functional Model, the RC directly communicates with the BA and TOP only and should have voice communications facilities with those Functional Entities. Communications to the GOP would come from either the TOP or BA. R2: The RC should only be required to have data links with the TOPs and BAs only. Data links from the GO,TO, GOP, LSE and DP would come from their host TOP or BA. The RC could have a process or provision in place to receive the data from those entities via the host TOP or BA in their RC area. Again, this is out of scope with the Function Model. R3: - Duke Energy suggests the following language: “Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.” The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals “who operates or directs the operation of the Bulk Electric System (BES) in Real-time.” System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the RC should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the RC needs to have the authority to deny that request. R4: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: “Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area.” We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by an RC. R5: Duke Energy has concerns that this requirement, as written, is not measurable. We seek clarity on the phrase “over a redundant and highly reliable infrastructure”. It is not clear to us what is considered an acceptable level of synchronism and reliability, and therefore have concerns how this will be measured. We suggest rewording this requirement for clarity or removing from this standard.
No
R1: No Comment R2: Duke Energy believes that this requirement, as written, would be an administrative burden on the RC to review all Operating Plans of a TOP and BA within their RC area. We suggest removing R2 or combining R2 and R3 because coordination of SOL(s) and IROL(s) and their mitigation plans would not exist without the RC reviewing the plans of the TOP and BA. In addition, we believe duplicative evidence would be provided for both R2 and R3 which is why we suggest combining the two requirements or removing R2 entirely. R3: See comment for R2 R4: Per the Functional Model, the RC would only notify impacted TOPs and BAs as to their role in the Operating Plan. Using NERC registered entities goes against the roles defined in the Functional Model and Duke Energy suggests rewording as follows: “Each Reliability Coordinator shall notify impacted BA(s) and TOP(s) identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).” In addition, the coordinated plans identified in R3 are only the coordinated plans provided by the TOP(s) and BA(s) in its RC area. R5: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC’s transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC to transition to its backup control center. If a RC is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R6: Requiring the RC to notify the TOP(s)/BA(s) on every exceedence of an SOL may be burdensome and will be operationally distracting to the current role of the RC which is having a wide area view of their RC area. R7: See comment for R6. The requirement, as written, presumes the TOP/BA will fail to act. We believe the RC should take actions only when either the TOP/BA failed to act or if the RC disagreed with the mitigating plans of the BA/TOP. As such, we suggest the following language revision: “Each Reliability Coordinator shall validate that the actions in the TOP(s)/BA(s) Operating Plan are appropriate and issue Operating Instructions, as necessary if: • The TOP/BA fails to implement the Operating Plan • The RC determines that the TOP/BA Operating Plan is insufficient” Duke Energy believes this language better aligns with the proposed TOP-001-3 R13 that already requires the TOP to notify and share their Operating Plan used to mitigate SOL(s) with the RC. The RC should only be responsible for validating the TOP(s) Operating Plan and taking action if, and only if, the TOP fails to act or the RC deems the actions taken by the TOP are insufficient. R8: See comment(s) for R6 and R7.
No
R1: The proposed definition for Operational Planning Analysis clearly relates to condition for next-day operations. However, the time horizon identified in this requirement (next day to 1 year out) is beyond the scope of the definition.

The proposed definition does not make reference to time horizons post next-day operations. In addition, the scope of R1 goes above and beyond the prevue of the RC as currently defined in the NERC Functional Model. . Duke Energy suggests removing Operations Planning and adding Real-Time Operations and Same-Day Operations. R2: Duke Energy suggest rewording R2 as follows: “The Reliability Coordinator shall distribute its data specification to Applicable entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.” The addition of “Applicable entities” will limit the data specification to only those entities that need to provide data to the RC. In addition, we have the same comment on Time Horizon as is stated in R1. R3: Suggest removing Operations Planning Horizon for the reasons mentioned above.
No
R1: We suggest changing “may impact other Reliability Coordinator Areas,” to “may impact adjacent Reliability Coordinator Areas.” This revision will reduce ambiguity on the expectations of the RC. Also, we suggest using only the term “Operating Plan” in this standard instead of the use of “Operating Procedures, Operating Processes, and Operating Plans.” We feel that Operating Processes and Operating Procedures are inherent in the definition of Operating Plan, and to list them out in this manner seems to indicate otherwise. R1.5: Similar language was removed from IRO-001-1.1 R3 with the justification “The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act.” The same logic should be applied here and this requirement should be deleted. R2: See comment above regarding the use of the term “Operating Plan.” R3: Duke Energy feels fails to see the differences in the responsibilities of this requirement from those addressed in R2 and R3 of the proposed IRO-010-2. We request that a distinction be made, or suggest the removal of this requirement, as it appears to be duplicative in nature. R4: Duke Energy suggests the removal of this requirement. We feel that a re-wording of R1.6 to the following would satisfy the responsibility, without the necessity of having a specific requirement for participation on conference calls. “R1.6: Provisions to schedule and participate in weekly conference calls.” R5: Duke Energy is concerned particularly with the use of the terms “Emergency” and “Impacted” in the proposed requirement. The use of the current definition of “Emergency” would result in a substantial amount of notifications to impacted RC(s). An argument could be made, that any action that an RC takes could have a ripple effect that would then prompt notification to impacted RC(s) in an inordinate amount of instances. Also, the term “Impacted” is too broad, and should be more narrowly defined. We suggest reverting back to the old language (Adverse Reliability Impact), as the proposed language does not appear to be selective enough in nature. R6: Duke Energy questions how an auditor is going to measure compliance with the phrase “shall operate as though the problem exits”. We suggest reverting back to the currently effective language of “operating to the most limiting parameter” as we feel this language is more effective at resolving possible disputes between RC(s). R7: Duke Energy suggest the following revision: “Each Reliability Coordinator that identified an Emergency shall develop an action plan to resolve the Emergency .“ We believe that no matter the circumstances, even if a dispute exists between RC(s), if an RC believes that an Emergency situation exists, the RC identifying the Emergency should be required to develop an action plan to mitigate said Emergency. R8: Duke Energy suggest the following revision: “Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.” We believe that no matter the circumstances, even if a dispute exists between RC(s), the impacted RC(s) should implement the action plan developed to mitigate the Emergency identified by the identifying RC. R9: We are unclear as to the need for the phrase “provided that the requesting entity has implemented its emergency procedures”. A requesting RC may not have an emergency procedure in place to mitigate the issue at the time of the event. We believe the intent of this requirement should be for RC(s) to help one another unless their assistance would violate safety, equipment, regulatory, or statutory requirements. As such, we suggest the following revision: “Each Reliability Coordinator shall assist Reliability Coordinators, if requested, unless such actions would violate safety, equipment, regulatory, or statutory requirements.”
No
R1: Duke Energy believes using the Operational Planning Horizon expands the RCs responsibility beyond next day operations and does not align with the responsibilities of an RC as defined in the NERC Functional Model. R1.1.2: Duke Energy suggests the following revision: ”Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).” Each RC should be able to define their process for submitting outage coordination data to fit their RC Area. R1.3/ R1.5: Duke Energy believes these two sub-requires are duplicative and suggests the removal of one of them. Please clarify the difference between the 2 sub-requirements. M2: Duke Energy suggests adding a provision that an attestation from the RC stating that their BA/TOP followed their RC Outage Coordination Process is acceptable evidence. R3/R4: Duke Energy recommends the removal of R3 and R4. The TPL Planning Assessments are not used in the Operations Planning horizon. Additionally, we fail to see the reliability based need for an RC to have the kind of analysis provided by a Transmission Planner/Planning Coordinator. The assessments made by a TP/PC are in located in the time horizon of 1-year and beyond, with some assessments potentially being as far as 20-years into the future. With the RC’s responsibility mainly focused on Real-time operations, we do not agree that providing the planning assessments alluded to in R3 and R4 is necessary.
No
Duke Energy does not agree with the proposed changes for TOP-001-3. Specifically, we have concerns that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the TOP/BA “act” to ensure the reliability of the its area is not only a requirement that the entity do its job for which other requirements are applicable, but also a requirement that could be interpreted to require that the TOP/BA “act” to cover

the full scope of any related reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirements should focus strictly on the communication desired when needed to ensure the reliability of the TOP or BA area. R1: The TOP is already required to act in other applicable standards. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R2: We disagree with the placing of the Balancing Authority here in this standard. We feel this is better placed within the BAL standard family. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R3: The definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R4: No Comment R5: See Comment on R3 R6: See Comment on R3 R7: See Comment on R3 R8: Duke Energy suggests removing the reference to the examples and suggests the following: “Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.” We believe the examples are not necessary in this requirement. R9: Duke Energy suggest the following revision: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected Applicable entities of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” We believe that “negatively impacted” is ambiguous and lacks clarity and suggest removing “negatively”. In addition, we believe using “Applicable entity” is a more appropriate term to use than NERC registered entities. Finally, we suggest adding “planned outages” in order to be consistent with Measure 9. R10: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: “ Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area. Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by a TOP. R11: We believe that this requirement is better suited in the BAL family of standards. R12: No comments R13: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC’s transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a TOP to transition to its backup control center. If a TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R14: Duke Energy suggests removing “Real-time monitoring” from this requirement. R15: No comments R16/R17: - Duke Energy suggests combining the two requirements and rewording as follows: “Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.” The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals “who operates or directs the operation of the Bulk Electric System (BES) in Real-time.” System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the TOP and BA should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the TOP and BA needs to have the authority to deny that request. R18: No comments
No
R1-R3: No comments R4: Duke Energy suggests using alternative language in sub-part 4.4. Currently 4.4 states: We believe the language used is too broad, and could be open to interpretation. We recommend the a re-wording to the following: “4.4: Contingency Reserve requirement obligations” This re-wording should reduce any unintended incorrect interpretations. Also, the removal of “deliverability capability” is necessary, as we feel that having the capability to deliver reserve requirements is inherent to the very nature of having Contingency Reserve obligations. R5: Duke Energy suggest using another term other than NERC registered entities. We suggest identifying those entities, per the Functional Model, that specifically interface with the TOP or use the term “Applicable entity”. R6: Duke Energy believes that the amount of documentation needed to be retained for this requirement would become very burdensome to the TOP and RC. In addition, the proposed IRO-008-2 requires the RC to coordinate Operating Plans amongst its TOP and BA and this appears to be redundant. Additional concerns we have with this requirement is that there does not appear to be a stipulation for submitting an updated plan, if conditions were to change. For example, an Interchange Schedule is subject to change multiple times. Ultimately, we feel that the RC should have a next day Operating Plan in place to acquire the data necessary for the RC to perform their Operational Planning Analysis, the TOP/BA should then be obligated to follow that plan. We don’t agree that a daily document is warranted. R7: See R6 comment. In addition, we believe this requirement belongs in the BAL family of standards.
No

R1: Duke Energy believes the Time Horizons should include Same-Day Operations and Real-Time Operations. This would capture the Time Horizon where Real-time monitoring and Real-time Assessments occur. R2: As written, Duke Energy believes the Time Horizon should be modified to Same-Day Operations and Real-Time Operations to be consistent with Real-time Monitoring. R3: No comments R4: No comments R5: No comments
No
Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 IRO standards that are proposed for retirement.
No
Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 TOP standards and 1 PER standard that are proposed for retirement.
No
While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC and/or TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC's transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC and/or TOP to transition to its backup control center. If a RC and/or TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC and/or TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement.
No
Duke Energy disagrees with the idea that every exceedance of a facility rating is an SOL(s) as indicated in the White Paper. We would also like to point out that this premise is not reflected in the currently enforceable Reliability Standards. Also, it appears as though the authors of the White Paper may have inadvertently over-complicated their explanation of what constitutes an SOL. We believe that the use of the term "actual flow" in place of Pre-Contingency would help improve the clarity of the examples given throughout the White Paper. Figure 1 on page 4: The table appears to be more restrictive at lower loading levels than it is at higher loading levels, and it also appears to be in conflict with the Operating Plan found on the next page with regard to Load Shedding. We also suggest adding language stating, that "unless the entity's Operating Plan addresses potential impacts and mitigating strategies to ensure potential impact is localized" at the end of the fourth and sixth bullets in Figure 1, this would improve the consistency. Steady State Voltage Limit Exceedance: We suggest striking the "or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event" from the paragraph. We feel that there could be auto-reactive supplies that may be available to bring the limit back to an acceptable range, also, a Real-time Assessment/situational awareness tool is designed to aid in managing the system and not designed to create exceedances and violations. Also, we suggest that a clause be inserted taking into account automatic or manual control of reactive resources that are accepted per FAC-011 for SOL(s). Ultimately, we feel that SOL performance is based on flows in Real-time, and that is the criteria that should be used to determine if you have exceeded or not exceeded. Stability Limit Exceedance: The first sentence of paragraph 4 which states, "SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability" appears to redefine what is considered an SOL exceedance. An SOL is supposed to have a value associated with it, and you exceed the SOL when you cross that value. The above referenced sentence describes an SOL exceedance as entering into an Operating space and then what the next contingency could result in. We feel that this language is not consistent with the definition of an SOL. Figure 2: Duke Energy is concerned that the language in Figure 2 is expanding the concept of SOL Exceedance. Of particular concern is the phrase, "unacceptable system performance equates to SOL exceedance," we fail to see how one could monitor this or even apply it. Also, we recommend the removal of bullets 2 and 4. It appears that bullet 4 is saying the same thing regarding voltage, as bullet2 is saying for facility ratings. Lastly, bullets 1 and 3 are not "Assessments." We suggest them being in their own category, as SOL exceedance should be based on actual system conditions. SOL Exceedance and Operating Plan: Duke Energy is concerned that the language used in this section blurs the line on whether you have exceeded an SOL or not. As currently written, the section reads as though that even after you have exceeded an SOL, it may depend on what happens afterward to determine if it was an actual exceedance or not. With the actual exceedance in doubt, it is difficult to know where an entity is from a compliance standpoint. Table 1 Operating Plan Example: We request removal and replacement of the terms "Non-Cost" and "Off-Cost" with more common industry terms, or insert an explanation of the terms used. Also, the use of the terms "load shed" in the Pre- and Post-Contingency Loading columns is somewhat misleading. Consider revising to more clearly state the expectations regarding the use of Load Shed in this context. Applicable Definitions: The term "Interchange" is used sporadically throughout the definitions section of the White Paper, we suggest changing to "known Interchange" for clarity. Also, we recommend removing the parenthetical at the end of Real-time Assessment and Operational Planning Analysis. Lastly, Phase Angle, Equipment Limitations, and Special Protection System should be listed as sub bullets as part of the Assessment, and not be a part of the definition.
No

1. As previously stated in TOP-001 R3, the definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written.
Yes
As stated in our comments above, Duke Energy has significant concerns regarding aspects of the proposed TOP/IRO standards. We believe they are in direct conflict with the current Functional Model roles and responsibilities upon which the industry has built processes, procedures, software, and infrastructure. The industry approved Functional Model defines the various relationship, functions, the tasks performed by these functions, the responsible time horizons and the relationships between the entities responsible for performing tasks associated with each function. It is this model that provides the foundation and the framework upon which NERC is to develop and maintain Reliability Standards. Furthermore, the idea that reliability begins with and centers completely around the RC is a mistake as it removes the defense-in-depth strategy currently in place. The RC should be the last line of defense, not the first. Reliability does not start with the RC; it begins with the TOPs and BAs and the standards should acknowledge and emphasize this important tenet of reliability. The RC's role is to maintain a wide-area view and prevent system events – having them involved in every TOP's normal operations at all times distracts from the RC's responsibility and will have significant consequences. Duke Energy is not opposed to visiting the re-assignment of said responsibilities and applicable time horizons, however, we feel that this task should be done through an amendment of the Functional Model, and not through the Reliability Standards process.
Individual
Thomas Standifur
Austin Energy
No
City of Austin dba Austin Energy (AE) does not agree with the change to R1, which removes the "clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE offers more comments on this matter with regards to TOP-001-3 below.
Yes
No
: City of Austin dba Austin Energy (AE) supports the separation of the Outage Coordination standard, though we believe it is not entirely necessary. R1 and R2 could be easily included in one of the other standards (where they were originally). AE believes R3 and R4 are unnecessary in their entirety and asks the SDT to remove them. AE does not understand the purpose they are trying to fulfill, as there is no mention of them in the mapping document. Further, AE believes R3 and R4 are redundant with requirements in TPL-001-4, which becomes enforceable on 1/1/15. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. Alternatively, IRO-017-1, R4 can be subsumed into IRO-017-1, R1, as any outage coordination should take place through the Transmission Operator. The RC can develop its R1 process to require the submittal of longer-term outages, if necessary, and outage conflicts would then be covered and resolved through R1 Part 1.4.
No
City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments on R1: (1) AE does not agree with the change to R1, which removes the "responsibility and clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to "act, or direct others … to act" while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. AE recommends combining the old and new R1 language to state "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed, including issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area." (2) AE does not agree with R10, which requires monitoring "neighboring Transmission Operator Areas to maintain reliability." Without additional guidance, many TOPs will be left with a requirement to monitor its neighbors' entire systems. The role of coordinating reliability is that of the Reliability Coordinator, as agreed by the SDT on the project's 6/12/14 webinar. During the webinar, the SDT stated the TOP should be aware of seams but it is the RC that has ultimate responsibility to ensure reliability across the seams. AE

respectfully requests the SDT to review this issue further and refine the requirements accordingly. (3) AE believes R7 is not necessary as written. Assistance requested from one TOP to another is just that, a request. If it becomes an issue of reliability, the TOP would need to involve the RC who has other requirements in place allowing the RC to issue an Operating Instruction to the necessary TOP(s). AE requests the SDT remove R7 from TOP-001-3.
Yes
Yes
Yes
Yes
No
City of Austin dba Austin Energy (AE) provides the following comments regarding VSLs: (1) The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. (2) The VSL for IRO-010-2, R2 should have the note regarding starting at the Severe VSL similar to TOP-003-3, R3 and R4 and others. (3) The VSLs for TOP-001-3, R3 and R5 should parallel the VSL for IRO-001-4, R2. (4) The VSLs for TOP-001-3, R4 and R6 should parallel the VSL for IRO-001-4, R3.
Yes
City of Austin dba Austin Energy (AE) provides the following comments on the definitions of Operational Planning Analysis and Real-time Assessment: (1) Consider changing the use of the term “Special Protection System” to “Remedial Action Scheme” to match Project 2010-05.2. (2) Please clarify what is meant by incorporating “identified phase angle and equipment limitations.” Does the SDT intend this to cover limitations in real and reactive capability? (3) Additionally, AE provides this third comment on the definition of Transmission Operator Area, which is rarely used in existing standards but is included in the TOP/IRO family revisions. In the ERCOT Region, both ERCOT ISO and each local control center are each registered as TOPs. A CFR matrix delineates the responsibility for each requirement applicable to the TOP function. The general concept in the ERCOT Region is that individual local control centers operate Transmission assets under the direction of ERCOT ISO. Logically, one would assume that each Transmission Operator would have a Transmission Operator Area. However, the current definition poses a potential conflict. As defined in the NERC Glossary, a Transmission Operator Area is “The collection of Transmission assets over which the Transmission Operator is responsible for operating.” ERCOT does not operate Transmission assets, rather, it directs the operation of Transmission assets. Therefore, AE suggests a revision and regional variance to the definition as follows: “Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation.”
Individual
David Jendras
Ameren
Yes
Yes
No
R3 – We operate as both a TO and BA. This change isn’t really negative, but it always seems strange to us when we say that as a BA we comply with instructions issued by the TO, which is us. We believe that NERC should have clarifying language that it is more intuitive for entities that operate as a combined BA/TO, so that requirements that state that the BA follows instructions/directives from the TO (or vice versa) are not applicable. R4 – We are concerned because "BA" is in the list of entities required to follow directives issued by the TO. Our current RSAW says this is NA since it is only for DP’s and LSE’s. Under the proposed draft with the BA listed in the requirement, we now have to state that as a BA, we follow directives given by the TO, which is also us, and in our opinion this doesn't make sense for the way we are organized. R6 – See my comments about BA's following instructions/directives from TO's as stated above. It also looks like they have new requirements stating that TO's will follow instructions issued by its BA. As stated earlier we have the same sort of comments, as for us, we are one in the same. R13 – We ask for clarification; does the

drafting team mean running something automatically like the RTCA, this, conceptually, is OK, since we run it every 2 minutes. However if the drafting team means something else, we need to object, as we simply don’t have manpower to perform manual studies every 30 minutes. The issue is, assuming the RTCA; would it be a reportable violation if the RTCA program goes down for longer than 30 minutes? We believe it would be a burden to ask entities to track and self-report instances where RTCA was down for 30 minutes or longer.
Yes
No
R1: We ask the drafting team for clarification. What data would be necessary from outside entities for us to perform "Operational Planning Analyses"? Would this need to be forwarded to those entities? R5: We ask the drafting team for clarification; how will we be able to prove compliance with this unless someone provided us with any data specifications satisfying said data specification transfer if it means an automatic type of data dump. Does the drafting team mean providing some data manually on a real time basis (line just tripped, etc), that would fall in the TOS realm or with ICCP data transfer?
Individual
Charles Rogers
Consumers Energy
No
I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context.
Yes
No
R6, R7, R8 – The Rationale says that “IROL exceedance” was replaced with “emergency”, but “emergency” does not appear in the Requirement; “IROL exceedance” does. It doesn’t appear that SDT did what they claim.
No
R1 – The Rationale refers to a R1, part 1.7, but no such part exists in the posted draft.
Yes
Yes
No
I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context. R5 and R6 – I generally agree, except for Reliability Directive vs. Operating Instruction as noted above. This should be Reliability Directive. R9 – I am concerned about the general treatment of outages discussed in the requirement. It is not uncommon to experience frequent brief outages – requirement should have a “of duration greater than <some value, perhaps 15 minutes>”. R10 – Individual TOPs may not be able to obtain monitoring access to adjacent TOP areas – this could create a compliance risk outside the entity’s control.
Yes
Yes
Yes
Yes
Yes

Yes
Yes
No
Individual
Daniel Duff
Liberty Electric Power, LLC
No
There is no requirement for the RC to identify the Operating Instruction as such. In some areas the same individual could be issuing a Directive, an Operating Instruction, or a market-related instruction. Unless the requestor identifies the status of the request, the receiver will have no idea if he is required to comply.
No
There are two types of data falling under the standard, and they should be treated differently in the requirements. Data requests are fine as written, but data transmitted automatically for real-time purposes should be handled with a seperate requirement. The requirement should be for the data provider to provide the specified data as required, but with a measure that shows the RTU or other data transmission device is installed and operational. There is no log of this data, and requiring an attestation is too burdensome for the RC, who may be required to provide hundreds of documents in response to the requirement.
No
There is no language regarding which entities the plan will be "made available" to. Generators should be included on the list so they can plan outages knowing the process being used to approve or deny requests.
No
See comment provided to the similar IRO standard.
No
See comment provided for the similar IRO standard.
Yes
Yes
No
No
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
Yes
Yes
Yes

Yes
Yes
No
PPL does support the standard. We recommend the drafting team use only the term, ‘Facility Rating’ and not use the term ‘derived limit.’ This will provide for consistency is use of one term. Requirement #18, “Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits,” should be changed to ◊ “, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in Facility Ratings.”
Yes
Yes
Yes
Yes
No
Yes
No
Individual
Brett Holland
Kansas City Power and Light
Individual
Scott Langston
City of Tallahassee
Individual
Bill Fowler
City of Tallahassee
Individual
Josh Smith
Oncor Electric Delivery LLC
Yes
Yes
No
Proposed Standard IRO-017-1 R3 states: “Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.” Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
No
Proposed Standard TOP-001-3 R9 states: “R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment…” In response to R9, Oncor recommends that the requirement make it mandatory for

RC’s and TOP’s to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it is necessary to notify registered entities that do not have reliability control functions to the BES. R10 as proposed requires each “Transmission Operator monitor facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area”. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor the facilities of neighboring TOPs. This requirement imposes a “one size fits all” regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. Oncor requests R10 be reworded to provide flexibility for region structure. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to “a continuous duration exceeding its associated IROL Tv”. This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncors recommendation is to keep the existing 30 minute time limit. Proposed R13 states: “Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes.” Oncor considers Real-time Assessments to be a Reliability Coordinator function. In the ERCOT region, Transmission Operators do not have the wide area overview that is required to perform the task. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator creates added expense and contributes no added reliability to the BES. Oncor requests R13 be reworded to provide flexibility for region structure.
Yes
Yes
Yes
Yes
As previously stated in response to Question 7, Oncor considers Real-time Assessments to be a Reliability Coordinator function. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added reliability to the BES. Oncor requests the SDT consider the applicability before responding to the periodicity.
No
Yes
Yes
Oncor does not support the two proposed definitions in proposed in Project 2014-03 Revisions to TOP/IRO Reliability Standards; Operational Planning Analysis and Real-time Assessment. The definitions state the minimum inputs that must be included in the evaluation of each Operational Planning Analysis and Real-time Assessment for pre and post contingency conditions. Some of the inputs listed that shall be included are not feasible for post contingency analysis, such as phase angles. For Oncor to approve the definitions, recommend changing the wording from “shall reflect inputs including” to “may reflect inputs including” in both definitions. Operational Planning Analysis Oncor’s proposed recommendation: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) Real-time Assessment Proposed definition: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)” Furthermore, Oncor has concern that the proposed Standards place unnecessary requirements on Transmission Operators (TOPs) to run Operational Planning Analysis and Real-time Assessments. As stated in response to Question 7 (TOP-001-3) and Question 12, the ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. Requiring Transmission Operators to replicate Real-time Assessments and Operational Planning Analysis currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added reliability to the BES. Oncor requests the SDT consider placing these functions (Operational Planning Analysis and Real-time Assessment) on the Reliability Coordinators only.

Group
Santee Cooper
S. Tom Abrams
Individual
Michael Moltane
ITC
No
ITC has concerns with the definition of "Real Time Assessment". Real time assessment is typically conducted by tools such as State Estimator and Contingency Analysis. Inclusion of known protection system and special protection system status or degradation is not practical or possible in real time simulations as these simulations are steady state analysis while studying protection system degradation requires a dynamic analysis. As suggested under comments on Operational Planning Analysis Definition, protection system degradations are studied when the outages on protection system or associated elements are planned. Including this analysis in real time assessment may require dynamic simulations every thirty minutes which is not practically possible and provides no additional benefits. ITC supports that unplanned protection system outages impacting BES reliability shall be evaluated and appropriate action should be taken however conducting this evaluation as part of real time assessment shall not be required. ITC recommends modifying this definition by removing protection system and special protection system status or degradation. Regarding R10, ITC recommends adding clarification to this requirement clearly outlining that it is up to the TO to determine which external facilities to monitor based on impact to their internal system. ITC also recommends removing sub-100 kV language as a sub 100 kV element needed to maintain reliability of the system should already be designated as part of BES. In reference to R14, ITC would like clarification from the SDT as to whether the the standard will include the methodology/examples listed in the SOL Exceedence White Papper.
No
In regards to the definition of "Operational Planning Analysis", ITC has concerns that the definition is too prescriptive in specifying required inputs for Next Day Analysis. Specifically, protection system and associated element outages are studied sometime several days ahead using relay clearing time and stability studies. These studies cannot be conducted daily for next day operations as the studies are time intensive and may require dynamic simulation. ITC is fully supportive of studying protection system outages and ensuring that these outages do not reduce the reliability of BES. However the definition should not restrict next day analysis to analyze these outages. Next day analysis is a steady state analysis conducted to ensure that system can operate reliably under all known contingencies. Including protection system outages in next day analysis will require dynamic simulation which is very different than steady state analysis, is very time consuming and does not provide additional value if such analysis has already been conducted when the protection system outage was planned. An alternate and more practical method is to include any potential over trip scenarios due to protections system degradations as these can be simulated by steady state analysis for next day conditions. The definition should be modified to allow the evaluation of protection system status or degradation analysis in the horizon deemed appropriate by the TOP.
No
Regarding R1.1, the inclusion of sub-100 kV facilities is not relevant as the requirement should focus monitoring on BES elements only. If a sub-100 kV facility is included in BES per the definition it should be monitored.
Individual
Mahmood Safi
Omaha Public Power District
Individual
Ayesha Sabouba
Hydro One

Yes
R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC-wide area review responsibility.
No
R-1 contains what appears to be a redundant P-81 type of issue between what is in COM-001-2 and this standard-Interpersonal Communication vs. Voice Communication. These requirements could introduce a double jeopardy issue for non-compliance and should be revisited by the drafting team and further explanation provided prior to support.
Yes
Yes
Yes
Yes
No
R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC wide area review responsibility.
Yes
Yes
Yes
Yes
Yes
No
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
Yes
Yes
Yes
Tri-State believes R1.1 is written too vague and open ended by stating "as deemed necessary by the RC." Tri-State would like for the team to rewrite that sub-requirement to clarify the intent.
Yes
Yes
No
Tri-State believes R10 is confusing as it is written. We believe the portion stating "…including sub-100kV facilities needed to maintain reliability…" is redundant as "Facilities" is a defined term that includes any element that is part of the BES. With the new BES definition, elements may be included through the Rules of Procedure exception process if they are important to the reliability of the BES.
Yes

As it is written R1 does not require the TOP to perform the analysis. The team should modify the requirement to "Each TOP shall perform an Operational Planning Analysis…."
Yes
Yes
Yes
Yes
No
Yes
No
Individual
Leonard Kula
Independent Electricity System Operator
Yes
No
We agree with all the requirements except R1. Requirement R1 appears to be largely redundant with Requirement R1 of COM-001-2. Requirement R1 of COM-001-2 requires each Reliability Coordinator to have Interpersonal Communication capability with the TOP and BA within the RC area and with each adjacent RC within the same Interconnection. By definition, Interpersonal Communication is "Any medium that allows two or more individuals to interact, consult, or exchange information." The difference between the two requirements appears to be the omission of Generator Operator in COM-001-2, which can be added to totally eliminate the redundant IRO-002-4 R1. We suggest the SDT consider presenting this option to the Standards Committee to initiate appropriate actions to avoid adding a P81 candidate.
No
We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word "Emergency". The Rationale box suggests that the language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word "Emergency" is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addresses as soon as possible without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to "Emergency", which should be corrected.
No
We agree with all the proposed changes, but are unable to locate R1, Part 1.7 as indicated in the Rationale box above R1, that: "Proposed Requirement R1, part 1.7 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." We are therefore uncertain as to how the concerns raised in Paragraph 92 (and in the next several paragraphs) of the FERC NOPR are addressed.
Yes
No
Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it's the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC: - Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.

No
We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that “Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.” This requirement seems out of place. Further it doesn’t provide any incremental value since it is written at too high of a level and would be difficult to measure. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP’s and OC’s recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator (in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest to remove the BA from R7. Requirement R9 stipulates that: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” The last part appears to be unclear as the “affected entities” can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the “associated communication channels between affected entities” will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to “between it and the affected entities”. Requirement R11 is out of place for the similar reasons indicated for R2, above. In addition the requirement seems inappropriate for the BA as it assigns transmission accountabilities which are not required in the Functional Model. We suggest removing this requirement. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart.
Yes
Yes
We agree with all the elements in the standard except the VSL for R5. Please see our comments under Q14, below.
Yes
No
We agree with all the proposed retirements except TOP-004-2, Requirement R4. R4 stipulates that “If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.” While the intent is covered by the revised definition for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, neither definitions specific ask for the verification of existing SOLs/IROLs or the determination of valid SOLs/IROLs as system condition changes that go beyond the conditions covered by previous SOL/IROL calculations. Requirement R4 thus should be retained (and mapped into TOP-001-3) unless the two definitions are revised to require the verification/determination of SOLs/IROLs through Operational Planning Analysis and Real-time Assessment. Not retaining R4, or without changing the definitions for the two terms, a responsible entity may project or enter an unknown state (for which valid SOLs/IROLs may not exist). An Operational Planning Analysis and Real-time Assessment at this time may indicate expected system performance, which may be unacceptable form a equipment loading, voltage level or stability viewpoint, but still there exist no SOLs/IROLs as a target to guide the responsible entity to adjust the BES to arrive at an acceptable state.
Yes
We agree with the 30 minute time frame. Further, we suggest the standard be strengthened to ask for developing SOLs and IROLs within 30 minute if there does not exist any predetermined or valid limits for the conditions being analyzed. This is particularly important when, for example, an entity has valid SOLs and IROLs for a set of system and operating conditions but an unplanned event that takes out some BES Facilities from service, rendering the previously developed SOLs/IROLs not valid. In this case, the responsible entity needs to recalculate the SOLs/IROLs for the new condition. A 30-minute is the appropriate time frame for the recalculation. The standard should specifically require that SOLs/IROLs be reestablished within this period.
No

We generally agree with the White Paper except the actions depicted for the Emergency (4 hr) condition in the example in Table 1. When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with 15 minutes or less to reduce flow within the 15-minute or 4-hour rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency Rating consistent with timelines identified in Operating Plan. The “as necessary and appropriate” qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the 15-minute rating.
No
a. IRO-008-2, R6: The LOWER VSL which makes reference to “Emergency” should be changed to “anticipated or actual SOL/IROL exceedance”. Please see our comment under Q3, above, for details. b. IRO-010-2, R1: The SEVERE VSL for R1 can be reworded to “The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.” Since there are only 4 parts in R1 and hence the “four or more” is inappropriate. c. IRO-017-1, R1: We do not believe the VSL for R1 should not be binary. R1 requires the RC to identify the roles and develop a process for coordinating outage plans, the latter to include several elements. It may well be a case where the RC did develop the process but missed some of the elements listed in Parts 1.1 to 1.4. For example, a LOWER VSL may be assigned if the RC did develop identify the roles and develop the process document, but missed one of the parts in 1.1 to 1.4. A MEDIUM VSL may be assigned if the RC missed two of the parts, etc. We suggest the SDT to review the VSL development guideline and FERC’s guideline, and revise the VSL for R1 accordingly. d. TOP-001-3, several requirements: Since we disagree with a number of requirements in this standard, we are unable to support the VSLs associated with these requirements. e. TOP-003-3, R5: This requirement contains 3 parts each of which specifies a particular aspect of data provision. It is conceivable that a responsible entity provided data as specified in R3 and R4 but failed to follow one or more of the specific format, process or protocol as depicted in Parts 5.1 to 5.3. Hence, having a binary VSL for R5 would imply that failing to meet just one of Parts 5.1 to 53 will render the responsible entity being assessed a SEVERE violation. This is inconsistent with the VSL guideline. We suggest the SDT to expand the VSL for R5 to cover the cases of failing to meet one and two of the three parts in R5.
Group
Bureau of Reclamation
Erika Doot
No
The Bureau of Reclamation (Reclamation) disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Reliability Coordinators and Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g. water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Reliability Coordinator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.
No
Reclamation believes that, like under IRO-002-2, Reliability Coordinators should be able to have data links with Transmission Operators and Balancing Authorities, who in turn communicate with Generator Operators and Distribution Providers. Reclamation believes that Reliability Coordinators should be able to elect this model so that Transmission Operators and Balancing Authorities are aware of all instructions regarding generation and transmission that are issued in their control areas.
No
Reclamation suggests that R4 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
Yes
Yes
No
Reclamation believes that Generator Operators should be included in the proposed outage coordination standard. Like TOP-003-1, IRO-017-1 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. The standard should acknowledge that generators may have unplanned outages due to safety concerns, equipment concerns, regulatory requirements, or statutory requirements.
No

Reclamation disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g. water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Transmission Operator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.
No
Reclamation suggests that R3 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
No
Reclamation disagrees with TOP-003-3's proposal to require Generator Owners, Generator Operators, and Transmission Owners to meet any data specification outlined by Transmission Operators or Balancing Authorities. Like TOP-003-1, TOP-003-03 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. Reclamation does not support TOP-003-3 because it does not clearly define what types of data entities can request or may be required to provide, and is likely to create operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas.
Group
BC Hydro and Power Authority
Patricia Robertson
No
The new Requirement has the Reliability Coordinator issuing “Operating Instructions” rather than “Reliability Directives”. The scope of “Operating Instructions” broadens to non-emergency situations. BC Hydro does not support this increase in scope.
N/A
N/A
No
The new Requirement has the Reliability Coordinator able to ask for “sub-100 kV’ data if it deems necessary. This is an increase in scope from the data the RC currently asks for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
N/A
No
The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP’s and BA’s follow. The responsibility for coordination should reside with the TOP’s and BA’s, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA’s responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage analysis. An RC driven coordination process does not account for differences and needs of TOP’s and BA’s, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA’s,

responsibility for assessment of system wide conflicts through study assessment, and development of conflict resolution processes to support operations.
No
BC Hydro’s concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of “Operating Instructions” broadens to non-emergency situations. Requirement R3 and R4 have the BA’s complying with TOP’s Operating Instructions. BC Hydro’s concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no “out” clause based on reliability conflicts – such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an “out” clause.
N/A
N/A
N/A
N/A
N/A
N/A
N/A
N/A
Group
Tennessee Valley Authority
Dennis Chastain
Individual
Ayesha Sabouba
Hydro One
Yes
No
R-1 contains what appears to be a redundant P-81 type of issue between what is in COM-001-2 and this standard- Interpersonal Communication vs. Voice Communication. These requirements could introduce a double jeopardy issue for non-compliance and should be revisited by the drafting team and further explanation provided prior to support.
Yes
Yes
Yes
No
We believe that IRO 017 -1 needs more work. From an Ontario perspective the TP and PC do not coordinate outages.
No
R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC wide area review responsibility.
Yes
Yes
No
I sent in comments earlier but I have updated them now to include comments about IRO-017-1.
Individual

James Nail
INDN - Independence Power & Light
Yes
No
Requirement R1 is very similar to Requirement R1 of COM-001-2 which requires the Reliability Coordinator to have Interpersonal Communication capabilities with the exception that COM-001-2 does not include a requirement for RC to have comm links with GOPs. For Paragraph 81 considerations, the two standards should be reconciled such that only one requirement is needed. INDN supports the comments submitted by Southwest Power Pool regarding Requirement R2. Requirement R5 requires a 'redundant and highly reliable infrastructure' for the exchange of data. There is some confusion as to whether this statement refers to redundant circuits providing data to a Control Center EMS or refers to an independent backup center as required by EOP-008. If in fact the infrastructure referenced is a backup center, then R5 is redundant and should be eliminated from the standard. Clarification is needed to resolve this question.
No
INDN supports the comments submitted by Southwest Power Pool.
Yes
Yes
No
INDN supports the comments submitted by Southwest Power Pool.
No
INDN supports the comments submitted by Southwest Power Pool. In addition R10 does not provide enough detail as to what the TOP's responsibility is. How far into a neighbor's facility are we required to monitor? At some point this should become the responsibility of the Reliability Coordinator, who has a much better regional view than individual TOPs. R13 attempts to make a "one size fits all" solution for performing Real Time Assessments. We believe this is too prescriptive and does not reflect a realistic approach to operations in some environments. For a TOP with no identified IROL or an entity that typically operates at low load levels it may not be necessary to perform a full assessment every 30 minutes. Small operations with minimal staffing will be unnecessarily burdened to perform, review and document assessments that add little or no Reliability benefit in these circumstances. A better approach may be to establish a threshold for system capacity or rate-of-change that would then trigger the 30 minute interval.
Yes
Yes
Yes
Yes
No
INDN supports the comments submitted by Southwest Power Pool. See also our comment to TOP-001 R13.
No
No
INDN supports the comments submitted by Southwest Power Pool.
No
Individual
NIck Braden
Modesto Irrigation District

No
MID believes that the implementation timeline for TOP-001-3 is not adequate to handle the business changes required by R13. MID suggests two years be allowed to implement R13.
Group
FirstEnergy
Cindy Stewart
Yes
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time.
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time.
Yes
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time.
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time.
Yes
While FirstEnergy generally supports TOP-001-3, we have concern with 30 minutes time frame for updates on Real Time Assessments. This obligation contradicts the 2 hour time frame set in EOP-008. Also, if there is a loss of data communications and there is a need to man substations; it may take longer than 30 min to stage personnel in the field.
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time
Yes
Yes
Yes
No direct FirstEnergy applicability - not thoroughly reviewed. FirstEnergy abstaining at this time. See comments for #7.
Yes
FirstEnergy recommends striking the words “or degradation” in the proposed definitions for both Operating Planning Analysis and Real Time Assessments.
Group
SPP Standards Review Group
Robert Rhodes
No
Since there is no red-line for IRO-001-4, delete the last sentence in the Rationale Box for the Applicability Section.
No
Requirement R1 is redundant in that Requirement R1 of COM-001-2 already requires the Reliability Coordinator to have Interpersonal Communication capabilities. Therefore, this requirement should be eliminated for Paragraph 81 considerations. Requirement R2 requires the Reliability Coordinator to have data links with several non-traditional functional entities that are not normally associated with the exchange of Real-time data. Data links have specific connotations associated with specific equipment such as ICCP, etc. We would suggest that the language in this requirement be revised to parallel the language in IRO-010-2, Requirement R2. This also parallels the language in the COM standards. We would go on to suggest that since the requirement for the data to be supplied is contained in IRO-010-2, this specific requirement is redundant and too prescriptive in that it addresses how the exchange of data is to be accomplished rather than the real objective of exchanging data which is addressed in IRO-010-2. Requirement R5

requires a ‘redundant and highly reliable infrastructure’ for the exchange of data. This appears to be redundant with EOP-008-1, Requirement R6 which already calls for backup control centers which are not dependent upon the primary site for functionality. Since redundancy is already required by EOP-008, there is no need for Requirement R5.
No
Hyphenate ‘next-day’ in Requirement R1. We suggest slightly rewording Requirement R3 to read: ‘Each Reliability Coordinator shall have a coordinated Operating Plan(s) for the next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities in Requirement R2.’ Requirement R5 requires a Real-time Assessment be performed at least once every 30 minutes. This is technically infeasible in some situations where there is missing data and/or the state estimator does not solve properly. An assessment cannot be completed under these conditions. Being a zero tolerance standard, this sets the industry up to fail. One of the largest categories of events being reported under event analysis is EMS or state estimator outages. Additionally, even if the state estimator does solve, can we be assured that the solution is correct in these situations? Also, just because the state estimator has solved doesn’t necessarily mean that each contingency in RTCA is a valid solution. The language needs to be modified to reflect this situation. Perhaps the requirement should be focused on a normal schedule for a Real-time Assessment every 30 minutes but consideration would be given for situations where the tools that are currently available to the industry simply cannot provide the desired outcome. If the standard maintains the 30 minute or some similar time frame requirement, logging the completion of those assessments and maintaining records will prove to be burdensome to the industry requiring additional personnel simply to staff this capability. This argument applies to the Transmission Operator in TOP-001-3, Requirement R13. Replace ‘Real-Time’ with ‘Real-time’ in Measure M5.
No
The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should be used to remove the Interchange Authority from the Applicability Section of TOP-003-3. There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize ‘Part’ in the Rationale Box for Requirement R1.
No
Replace ‘the problem’ with ‘an Emergency’ in Requirement R6.
No
The recent trend at NERC is to eliminate subparts. Therefore, change the formatting on Requirement 1 Subparts 1.1.1 and 1.1.2 to bullets. We recommend that Requirement R3 be deleted in that it is redundant with TPL-001-4, Requirement R8. If the Reliability Coordinator has a need for the assessment, the Reliability Coordinator can request a copy of the assessment from the Planning Coordinator and Transmission Planner who are then obligated to provide a copy of the assessment to the Reliability Coordinator.
No
We recommend the Real-time Assessment and Operational Planning Assessment definitions include the following change: ‘The assessment may reflect inputs including, but not limited to: load, generation output levels,…’ This will provide some flexibility for the TOP and BA to factor in those variables which can potentially impact the assessments without being so overly prescriptive that they must be included in all assessments. We recommend deleting Requirements R1 and R2 because they are redundant to the entire collection of Reliability Standards. If a Transmission Operator or Balancing Authority does not do what is being required in R1 and R2, they are non-compliant with many of the remaining standards. This then appears to be redundant and these requirements should be deleted based on Paragraph 81 considerations. Insert a ‘to’ between the ‘do’ and the ‘due’ in the last line of the Rationale for Requirement R3. Replace ‘Transmission Operator’ in the 3rd line of M5 with ‘Balancing Authority’. Replace ‘Balancing Authority’ in the 6th line of M6 with ‘Transmission Operator’. We recommend the following language for Requirement R8: ‘Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of actual or expected conditions that it has identified which could potentially result in an Emergency.’ Requirement R9 requires the Transmission Operator to notify negatively impacted NERC registered entities. This is too broad and needs to focus on those entities which the Transmission Operator is aware that they are using the data and that the impact is of some significance. Additionally, this could prove to be burdensome on the industry for those situations where telemetry is repeatedly dropping out and restoring itself. We recommend the drafting team address the concept of significance and include a minimum down-time such as 30 minutes which is already incorporated in EOP-004-2, Attachment 1. Requirement R10 requires the Transmission Operator to monitor Facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area. While we understand the intent of the requirement, we have concerns that in an audit situation or following an event, the question will be did the Transmission Operator go far enough into the neighboring Transmission Operators Area. How far is far enough in this situation? Where does the responsibility for this monitoring transfer from the Transmission Operator to the Reliability Coordinator? Additionally, there appears to be redundancy between Requirement R10 and Requirement R1 in TOP-003-3 in that the later requests the data to allow for Real-time monitoring. We suggest eliminating Requirement R10. If the requirement must remain, we recommend the drafting team consider referring to the data requirement in TOP-003-3, Requirement R1 and specifically state that the extent of the data to be requested

from neighboring Transmission Operators be determined by the Transmission Operator. Replace 'Tv' in the 3rd line of M12 with a subscripted 'Tv'. Regarding Requirement R13, please see our previous comments in response to Question 3 on IRO-008-2 associated with the 30-minute Real-time Assessment requirement. A similar argument holds for the TOP in TOP-001-3. Additionally, in the situation with smaller Transmission Operators, there may be an issue with the time required to acquire Real-time Assessment capabilities. For those smaller entities which may not be currently performing this role, it may take longer than a year for them to obtain this capability. Additional time should be provided in this situation. For example, TOP-003-3, Requirement R5 allows for more time for those entities which are not currently providing the data required in TOP-003-3, Requirement 1. A similar allowance should be included in Requirement R13. Replace 'Real-Time' in the 2nd line of M13 with 'Real-time'. Requirements R16 and R17 require the Transmission Operator and Balancing Authority, respectively, to provide its System Operators with the authority to approve planned outages of its monitoring and assessment capabilities. Does this apply to a single RTU or is it intended to cover only the full range of EMS capabilities? What is meant by 'derived limit' in Requirement R18?
No
Please see our comment on the definitions of Real-time Assessment and Operational Planning Assessment in Question 7. We suggest modifying Measure M4 to read: 'Each Balancing Authority shall have evidence that it has developed a plan that incorporated the criteria identified in Requirement R4. Such evidence could include but is not limited to dated operator logs or e-mail records.'
No
The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should be used to remove the Interchange Authority from the Applicability Section of TOP-003-3. There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize 'Part' in the Rationale Box for R1. Replace the 2nd line in the 2nd paragraph in the Rational Box with 'The language has been moved from approved PRC-001-1.' Capitalize 'Part' in the Rationale Box for R5.
Yes
No
With the retirement of Requirement R1 of PER-001-0.2, the requirement for operating personnel to have the responsibility and authority to operate to maintain the reliability of the BES is eliminated. Such action reverts to conditions pre-1965 and the Northeast blackout. Do we as an industry feel this is where we need to be at this time? Where does that responsibility and authority lie following retirement? Is this captured in other requirements in the standards? If so, which ones?
We tend to lean toward a not so prescriptive quantitative time limit but toward a more practical justification for why the assessment is needed. It can be dependent upon current system conditions where during light load conditions Real-time Assessments may not be needed as frequently as they are during peak load conditions. Even this can be different from system to system. Some may encounter congestion during light load periods and others may not. It's too dependent on too many variables. We feel that consideration should be given to situations like this rather than a one-size fits all 30-minute rule.
No
We have concerns with the implications in the last paragraph on Page 2. The implication here is that a set of SOLs defined at some previous time may not be adequate to protect the reliability of the BES. We agree with this concept but believe the white paper needs to recognize the fact that the list of SOLs may not necessarily be stagnant. If this pre-defined listing is updated continuously in Real-time, it is a very accurate representation of the limitations on the system at any given time. The white paper doesn't provide for this additional concept and should. Capitalize 'Real-time' in the 1st bullet at the top of Page 9. Also capitalize Bulk Electric System in the 2nd bullet. Delete the comma in the last line of the definition of Emergency Rating.
No
TOP-001-3 Delete the phrase '…in Severe VSL for Requirement R3 citing one of the specific reasons shown in Requirement R3.' This will make this VSL parallel the Severe VSL of Requirement R6. Either that or add the phrase to the Severe VSL in Requirement R6. Change all the VSLs such that they read: '…that result in, or could result in, an Emergency in those respective Transmission Operator Areas…' The proposed VSLs for Requirement R13 address not completing the Real-time Assessments within a specified time frame. This makes no adhering to the 30-minute criteria a zero-tolerance requirement. Why not use criteria that are more flexible and reflect a measure of up-time for the assessments? For example, Real-time Assessments were completed within more than 98% but less than 100% of the 30-minute windows during a calendar year. The way the VSL is written if one assessment is not completed within 30 minutes, the entity is just as guilty as if none of the assessments are completed. TOP-002-4 Change 'will exceed' in the Severe VSL for Requirement R1 to 'exceeded'. Change 'does' in the Severe VSL for Requirement R4 to 'did'. TOP-003-3 Capitalize 'Real-time' in the Severe VSL for Requirement R3. We suggest adding the phrase 'as specified in Requirement R5' at the end of the Severe VSL for Requirement R5. IRO-001-4 Use a lower case 'issued' in the Severe VSL for Requirement R3. IRO-008-2 Replace 'have an' with 'perform' in the Severe VSL for Requirement R1. The

requirement calls for the Reliability Coordinator to perform an Operational Planning Assessment, not to have an assessment. Add the phrase ‘in Requirement R2’ at the end of the Severe VSL for Requirement R3. Rather than tie compliance to the timing of a single Real-time Assessment in the VSLs for Requirement R5 making this a zero-tolerance requirement, we recommend that the SDT use a performance based, on-time criterion. For example, the Lower VSL could be The Reliability Coordinator performed a Real-time Assessment at less than 100% of the time but more than 98% of the time. The Moderate, High and Severe VSLs would be adjusted in a similar manner. We recommend the Moderate, High and Severe VSLs for Requirement R6 begin with ‘The Reliability Coordinator did not notify a total of X impacted Transmission Operators or Balancing Authorities…’ A similar change needs to be made for the Moderate, High and Severe VSLs for Requirement R8 except that the ‘or’ is already used there. Replace ‘are’ with ‘were’ in the Severe VSL for Requirement R7. Replace the ‘has been’ with ‘was’ in all the VSLs for Requirement R8. IRO-010-2 Capitalize Part in the Lower, Moderate and High VSLs for Requirement R3. IRO-014-3 Replace ‘failed to’ with ‘does not’ in the Severe VSL for Requirement R1. Add the phrase ‘specified in Requirement R2’ at the end of the Lower, Moderate and High VSLs for Requirement R2. Insert ‘has the’ between ‘Coordinator’ and ‘Operating Procedures’ in the Moderate VSL for Requirement R2. Insert ‘the’ between ‘has’ and ‘Operating Procedures’ in the Moderate VSL for Requirement R2. Insert ‘all’ between ‘meet’ and ‘three’ in the Moderate VSL for Requirement R2. Replace ‘does’ with ‘did’ in the Severe VSL for Requirement R2. Aren’t the Severe VSLs for Requirements R1 and R2 identical and therefore creating a double jeopardy situation? Insert ‘as specified in Requirement R3’ between ‘Coordinators’ and ‘in’ in all the VSLs for Requirement R3. Replace ‘the problem’ with ‘an Emergency’ in the Severe VSL for Requirement R6. Replace the Severe VSL for Requirement R9 with the following: ‘The Reliability Coordinator did not provide assistance to a requesting Reliability Coordinator that had implemented its emergency procedures and such actions could have been physically implemented or would not have violated safety, equipment, regulatory, or statutory requirements.’
Yes
There are numerous instances in the Measures of all the proposed standards where the phrase ‘but not limited to’ is included. In some instances this phrase is set off by commas and in others it is not. When the commas are used, the second comma appears out of place. We suggest deleting the commas entirely as it is done in several of the Measures. Requirements R10 and R11 in TOP-001-3, Requirement 1, Part 1.2 in TOP-003-3, Requirement R4 in IRO-002-4, Requirement R1, Part 1.2 and the revised definitions for Operational Planning Analysis and Real-time Assessment include a reference to the term Special Protection Systems. There is a new proposal at NERC to replace this term with Remedial Action Scheme. If this change comes about, how will this change be reflected in this set of revised standards?
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
To avoid requiring the distribution of the Planning Assessment within separate standards, LES recommends that requirement IRO-017-1 R3 be removed altogether. TPL-001-4 R8 already allows for “any entity that has a reliability related need” to submit a request for the Planning Assessment. Dividing what is essentially the same requirement between two separate standards introduces unnecessary compliance risk for registered entities. If the drafting team believes the RC should be identified as a recipient, then TPL-001-4 should be revised to reflect this change. As currently drafted, R4 would require the Planning Coordinator and Transmission Planner to coordinate solutions with the RC for issues identified during planned outages in the Planning Assessment which can extend into the Planning Horizon. To ensure the correct timeframe is reflected in the standard, LES recommends revising R4 to specify that the PC/TP/RC should only coordinate solutions in the Operations Planning Horizon (Operations planning horizon is next-day to one year out), and not outside the Operations Planning Horizon into the Planning Horizon. The RC should coordinate solutions within the RC area.
No
As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the plan is modified or not. To avoid unnecessary administrative work, recommend each Operating Plan only be provided once to the RC, unless notified by the RC.

Group
ACES Standards Collaborators
Ben Engelby
No
(1) We agree with the removal of the PSE and LSE from IRO-001-4. It would be highly unusual for an RC to issue a directive to a PSE or LSE. (2) The use of “operating instruction” as a FERC-approved defined glossary term is problematic because FERC has not approved COM-002-4. We recommend including the proposed definition of Operating Instruction, as stated in COM-002-4, in the Rationale Box above R1 that discusses the change from Reliability Directive to Operating Instruction. (3) We support the consolidation of IRO-004-2 by inserting the Transmission Service Provider into R2 and R3. We encourage the drafting team to further look for opportunities to reduce requirements and redundancy in the IRO and TOP standards. (4) For Requirement R2, we question the phrase “cannot be physically implemented” and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (5) For Requirement R3, we believe this requirement should be removed in its entirety. It meets Paragraph 81 criteria as an administrative documentation requirement. R2 clearly states that the applicable functions must comply unless there is a violation of other factors. The burden in R2 is on the entity to comply or to prove why they cannot comply. Therefore R3 is not needed. (6) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
No
(1) The list of entities that the RC should have data links with should be reduced to include only operational entities. Inclusion of Planning Coordinators does not make sense because they have no real-time data to provide. We question inclusion of equipment owners such as TOs and GOs since the associated operational entities are already included. The associated operational entities should be able to provide any data that the equipment owner can provide. (2) Requirement R4 is problematic as written because it implies that sub-100 kV transmission equipment are Facilities (i.e. the NERC defined term). They may be if they are part of the BES Otherwise, they are not. A simple solution would be to remove the clause “including sub-100 kV facilities needed to make this determination”. If these sub-100 kV facilities are needed they should probably be part of the BES and will be covered by the NERC defined term “Facilities” making the clause superfluous. (3) For Requirement R5, we recommend removing the phrase “highly reliable.” This is subjective, vague, and does not belong in a reliability standard. Redundancy should provide the requisite reliability for monitoring systems. If the drafting team believes that RCs should have tertiary redundancies or meet some service level, then state that as a requirement. (4) For Requirement R5, we also question the term “giving particular emphasis to alarm management” because it is ambiguous, vague, and not measurable. (5) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
No
(1) For Requirement R1, there is an incorrect glossary term listed. The term should be “Reliability Coordinator Area” not “Reliability Coordinator Wide Area.” There is no listing of any new proposed terms, so this needs to be aligned with the correct term in the NERC glossary. (2) Requirement R3 is wordy and leads to confusion. There is no need to cross reference R1 and R2, as this is a natural succession of requirements. This requirement should be combined with R1. (3) Requirement R4 should be combined with R1. (4) Requirement R5 should be combined with R1. (5) The drafting team should reevaluate this standard and consider options to consolidate and combine requirements. There are several areas stated above that could be grouped together into a single requirement or fewer requirements that would still meet the purpose of the standard.
No
(1) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (2) Requirement R2 should be combined with R1. A simple insertion of “maintain and distribute” in R1 would result in the same outcome with fewer requirements to comply with. (3) Requirement R3’s language of “mutually agreeable” is challenging for compliance because it requires additional documentation to show that the data was submitted in a “mutually acceptable format.” The requirement should be that entities must submit the applicable data by the required timeline. The SDT has made a straight-forward process very complicated for compliance purposes.
No
(1) We question the rationale for R6 and ask the SDT to provide examples or guidance in the technical reference guide for scenarios where RCs would disagree whether there is an Emergency or not in an Interconnection.
No

(1) Requirement R2 needs to be clarified, as it leaves too much room for interpretation from auditors. What does "follow" mean? Does this mean to follow Operating Instructions? If so, then it would be redundant with IRO-001. If "follow" means to have a copy of the RC outage coordination process, then it meets Paragraph 81 criteria as an administrative task. We recommend striking requirement as there are other methods for the RC to ensure that the TOP and BA will "follow" the RC instructions for outage coordination.
No
(1) For Requirement R3, we question the phrase "cannot be physically implemented" and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (2) We recommend combining R4 with R3 and R6 with R5. Language could be easily added to notify the inability to comply with the Operating Instruction. This is the same comment for combing R6 with R5. (3) For Requirement R7, we question the need for this requirement since an entity is already subject to comply with Operating Instructions. Operating Instructions would include assistance relating to emergency procedures. This requirement is redundant and should be removed. (4) Requirement R8 is problematic as currently written. At what point must a TOP notify the RC, BA, and other TOPs of "expected operations that could result in an Emergency?" We recommend focusing on actual operations that result in actual Emergencies. Furthermore, examples do not belong in a requirement and should be moved to the application guidelines. (5) For Requirement R9, what is the timing of notifications? The requirement does not define "negatively impacted interconnected NERC registered entities" and therefore is vague. Can other entities be positively impacted? We recommend clarifying this requirement. (6) We disagree with Requirement R10 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. TOP-001-3 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (7) For Requirement R13, we ask the SDT to clarify that registered entities are not required to install real-time state estimation to perform its Real-time Assessments and can rely on other methods to perform the assessment such as reviewing its RC's results. (8) For R14, the language is confusing. We suggest changing "as part of its" to "identified in its." This will make clear that the SOL is identified in the Real-time monitoring or Real-time Assessment. (9) For Requirement R15, we question the value of TOPs stopping what they are doing to alleviate a SOL violation to call the RC to tell them their plan. It seems to make better sense for the TOP to focus on the returning the SOL to within limits when it is exceeded and contact the RC if the TOP enters into an Emergency. (10) For Requirement R18, how does the drafting team define "derived limits"? This requirement is unnecessary because the TOP, BA, and GOP are required to comply with Operating Instructions.
No
(1) Requirements R2, R3, R6 could be combined with R1. There is overlap within these requirements and the notification requirements are vague. (2) Requirements R4, R7 and R5 could also be combined. There is overlap within these requirements and the notification requirements are vague.
No
(1) Requirement R5's language of "mutually agreeable" is challenging for compliance because it requires additional documentation to show that the data was submitted in a "mutually acceptable format." The requirement should be that entities must submit the applicable data by the required timeline. What should be a straight-forward process has been complicated for compliance purposes with this language.
Yes
We agree with the retirement of the above mentioned standards.
Yes
We agree with the retirement of the above mentioned standards.
Yes
We understand the rationale for using 30 minutes for performing Real-time Assessments and believe it is sufficient. We ask the SDT to clarify that registered entities are not required to install real-time state estimation to perform its Real-time Assessments.
Yes
(1) If the drafting team has identified "much confusion with – and many widely varied interpretations and applications of – the SOL term," then why not revise the definition of SOL in the NERC glossary? The whitepaper provides clarification, but this document may be lost over time. We recommend that the drafting team discuss revisions to the glossary term to determine if additional clarity can be provided.
No
(1) As mentioned in earlier comments, there are several instances in the standards where binary treatment is made to the VSL table where graduated violations could be implemented. (2) In regard to VRFs, we question the need for any requirement that has a low risk factor. We ask the SDT to review the Low VRF requirements to determine if these tasks truly impact reliability.
Yes

(1) We recommend that the drafting team post redlines with each standard, so it is easier to view the proposed changes. Having clean copies of the revisions only adds more time to have to track changes and it is a very inefficient use of industry's time. (2) The drafting team should consider reducing the amount of information in the posting, or extending the comment period to allow for a thorough review by industry. We recommend holding a technical conference or a series of webinars (instead of just one) to go through each of the standards in detail. The amount of information cannot be covered in a single hour-long webinar. (3) Why did the SDT not review PRC-001? The words "coordinate" and "familiar" are ambiguous words that have caused issues with compliance and enforcement for years. It is disappointing that this issue has not been addressed. (4) Thank you for the opportunity to comment.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
The retirement of IRO-004-2 is predicated on the concept that an Operating Instruction applies outside of the real-time time horizon. Operating Instruction as defined is for real-time and not for the Operations Planning time horizon. As such, it does not cover the purpose and timeframe identified in IRO-004-2. Directing others to act outside of real time does not make sense as deciding to take actions in a future time is a plan, not a real-time instruction. Additionally Operating Instructions have no COM-002-4 requirements associated with a Transmission Service Provider. In summary, while the use of the term Operating Instruction provides some uniformity, it simply does not work in its current form for the Operations Planning timeframe. Some instructions outside of the real-time time horizon are carried out by systems or on non-recorded lines and perhaps even by operations support personnel. The definition when created by the OPCP SDT was for COM-002-4 and was not for the construct of current proposed IRO-001-4 draft. Any modifications to the definition could create issues for the COM-002-4 standard as well. ERCOT recommends removal of the operations planning time horizon and address needs separately for expectations related to that time horizon for issuing instructions as necessary to plan for reliable operations. As an alternative, the definition could be modified and COM-002-4 modified to include "Real Time" in front of every instance of usage for "Operating Instruction" effectively moving real time out of the definition and making it an individual qualifier for each requirement as needed. For IRO-001 R1, ERCOT believes the existing requirement does not provide overlap as it ensures that entities have policies or controls providing such authority. The body of all other requirements provides the basis of the actual implementation of such authority through actions or directing to act. The current requirement appears now to be redundant with every other requirement that requires action from an RC. The evolution of this requirement has lost the "clear decision-making authority" portion which while not action-oriented provides a basis for System Operator judgment and authority. Having requirements worded this way can be a blanket requirement utilized by auditors to second guess an operator's perceived actions or inactions as a violation, while not regarding the clear decision-making authority a System Operator exercises with information available at a specific point in time. Additionally, when the current version IRO-001-1.1 loses the "within 30 minutes" language, it loses the original construct of this being a real time requirement and not something applied to same day or operations planning timeframe. It loses its purpose when trying to simply consolidate IRO-004 language with it. ERCOT recommends maintaining existing R1 language as much as possible as follows: "Each Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Reliability Coordinator Area. These actions shall be taken without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, and provide a timeliness requirement where appropriate for all requirements that require action by an RC in real time without redundancy. Additionally, recommend changing R1 to be actionable to current proposed language is inconsistently applied (e.g. TOP-001-3 R16, R17).
No
ERCOT does not agree with the rationale for deleting R2 of IRO-002-3. EOP-008 is an emergency operating plan for loss of primary control center functionality. Most instances of the situations that R2 applied to are not emergency situations, but for having alternative means of accomplishing required reliability tasks during the timeframe that analysis tools may be unavailable.
No
The reference in R6 and R8 to "as indicated in its Operating Plan" is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly that can cause a "plan" to vary and the impacted entities to vary. That phrase should be deleted. In R7, "to deal with" should be replaced with "to prevent or mitigate". In R2-R3, the current definition of Operating Plan states "a document". While this context is appropriate for processes/procedures determined well in advance of real time. The timeframe described is really next day and while most "Operating Plans" are documented, all plans to operate reliably may not be documented or in "a document". The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having "a document" rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single "document" and have several required elements. This can be overly prescriptive and burdensome. R4 further should not be limited to verbal or written notification if it remains. Some "plans" could be to commit additional generation. In the day-ahead process, the "notification" could occur via systems or other equivalent means. The connotation of a "document" and "notification" identifying "roles" creates a layer of inefficiencies and

manual administrative actions that are unnecessary if the planning and notification occurs via other means. R5 does not have any context surrounding it if an entity loses real time tools it utilizes to conduct a Real Time Assessment. It should not be a violation if an entity has analysis tool outages that cause a reasonable time deviation from a normal 30 minute timeframe. For example, if real time tools are not available some effort is given by System Operators in troubleshooting and corrective actions to make the real time tools available again. For example, by allowing 45-60 minutes as an alternative means, like conducting offline studies, is more reasonable to allow time for initial troubleshooting, then a decision to run the offline study, then to actually conduct the offline study without a violation for an abnormal situation that is still handled in a reliable fashion. While the current requirement has 30 minute requirement, IROLs are typically determined ahead of time or are so specific that the N-1 limit may still be valid if system topology has not changed thus allowing for continual Real Time Assessment even if the tool is unavailable temporarily. The introduction of SOL for the 30 minute Real Time Assessment introduces a new challenge relative to that of Real Time Contingency Analysis for thermal and voltage exceedances and all of the Facilities it takes into account vs the limited ones for IROLs. Currently proposed R8 is problematic for the ERCOT RC as potential SOL exceedances may show up as post contingency thermal facility rating exceedances that are then managed by the ERCOT Nodal market operations system as detailed in IRO-006-TRE. To notify a Transmission Operator that may or may not have to take a manual action depending on if the ERCOT Nodal market operations system resolves the SOL exceedance, would be unduly burdensome and result in a high volume of unnecessary communications. It should be explored as an alternative way to clarify somehow that it would be limited to actual "basecase" facility rating exceedances, not post contingency for thermal limits or for N-1 stability/IROL type exceedances. Alternatively, allow for the RC to identify when it would be appropriate to notify the impacted entities and when not to in its Operating Processes and Operating Procedures to notify an entity. As it stands today, it is not feasible.
No
Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems, will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
No
R3 and R5 appear to be redundant. R5 would be under the notifications identified in R3. If the SDT does not believe R1 is explicit enough to identify emergencies under R1.1., then clarify R1 so that R5 can be deleted. While other requirements use the term "impacted" to limit Emergency to just those that raise to the level of needing coordination with other RCs, R7 is silent and although infers, if read solitarily, could create the issue of interpreting all "Emergencies" which is not the intent. ERCOT suggests including language that limits R7 scope to only those Emergencies that rise to the level of needing coordination with other RCs, since the SDT has chosen to replace Adverse Reliability Impact with Emergency as that term includes local Emergencies as well. R9 (and TOP-001-R7) make sense from the context of having additional circumstances arise in real time that were not "planned" actions. It allows for assistance outside of agreed upon and coordinated plans to take place. This is accurate in that you cannot plan for every type of occurrence that is possible. If this is the context that the SDT imagined, ERCOT recommends capturing such concept within the RSAW. If it is not, ERCOT recommends deleting both requirements as it is redundant to the requirements requiring actions per plans to be taken. It would be beneficial to see the auditor's approach to expectations associated with RCs that are in separate Interconnections connected via DC Ties in the RSAW for IRO-014. DC Ties are viewed as resources or loads within the ERCOT Interconnection. While R4 is clear on the issue, the other requirements are vague.
No
ERCOT believes "develop" in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 "document and" with "maintain", which is sufficient. Document is purely administrative. M1 infers a requirement by including "dated". By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. R3 should be incorporated into TPL-001-4 R8 if it is necessary. R4 is vague and may be duplicative with TPL-001-4 R2.7 which requires development of a Corrective Action Plan whenever system performance (with known outages modeled) doesn't meet Table 1 requirements. R1.5 should address evaluation of outages in an operations planning timeframe. If more specificity is needed to address within XX amount of days in advance, that should be clarified.
No
Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: "Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states "a document".

Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term “Operating Instruction” outside of real time.
No
The current definition of Operating Plan states “a document”. Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4. For R4, the SDT should consider consistency of use of “Demand patterns” and “Load Forecast”.
No
Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
No
ERCOT agrees with retirement of IRO-003-2, IRO-005, IRO-015, and IRO-016. ERCOT does not agree with the current method to retire IRO-004-2 because the current definition for Operating Instruction is for Real Time only.
No
TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.
Yes
ERCOT believes that 30 minutes is the correct periodicity for normal operations. There should be flexibility in the requirement to account for instances when analysis tools may be unavailable temporarily recognizing the balancing of time to both trying to make the tools available again and or taking alternative means of conducting a Real Time Assessment. Recommendation could be to amend the requirement allowing for notification to affected entities and taking alternative actions to conduct a Real Time Assessment within 60 minutes of the last RTA.
Yes
Table 1 identifies trending/monitoring and non-cost actions to prevent contingency from exceeding emergency limit. Some entities may only alarm/trend/monitor when post-contingency loading approaches within a threshold or exceeds the emergency limit. This minimizes unnecessary attention to post-contingency loading that an operator has sufficient time to reduce loading if the contingency were to occur. Transient instability (angular, undamped oscillations) can be in addition to voltage instability, be local instability limits and not qualify as an IROL.
No
Please reference above comments regarding individual draft standards.
Yes
ERCOT believes that significant progress has been made to address the FERC orders, expert recommendations, and remove redundancies while maintaining reliability-based requirements. Outside of the issues raised in our comments and the IRC SRC comment, ERCOT supports the remainder of the proposed changes.
Individual
Joe Tarantino
Sacramento Municipal Utility District/Balancing Authority Northern California

No
No, the IRO-002-4 VSL provide no alternative other than Severe. In cases where one element of several hundereds could be missed this effectively creates a zero tolerance.
Individual
Gordon Dobson-Mack
Powerex Corp.
Individual
Richard Vine
California ISO
No
The wording in proposed TOP-001 requirements R1 and R2 contains the following phrase: "by issuing Operating Instructions, to address its reliability functions". The term "reliability function" is not defined in the standard or in the NERC Glossary of Terms, especially as it applies to each individual entity (ie – "its reliability functions") and is therefore too vague and subject to interpretation. These requirements could possibly reference "reliability-related tasks" which are required to be defined by PER-005, however this might not be inclusive enough because there might be unanticipated situations when an Operating Instruction is necessary to maintain reliability but isn't related to a documented task. The ISO would propose changing this wording to something like "by issuing Operating Instructions, for reliability purposes" or "by issuing Operating Instructions, when necessary to maintain reliability".
Individual
Karin Schweitzer
Texas Reliability Entity
No
There appears to be a gap between IRO-001-4 and IRO-002-4 related to Operating Instructions. In COM-002-4, Operating Instructions are issued either as an oral two-party communication, multi-party burst communication, or written. IRO-002-4, R1, requires the RC to have voice communication facilities with TOPs, BAs and GOPs. IRO-002-4, R2, requires the RC to have data links with BAs, PCs, TPs, GOs, LSEs, TOPs, TOs and DPs. IRO-001-4 R2 states that TOPs, BAs, GOPs, TSPs, and DPs shall comply with RC Operating Instructions. The possible gaps lies in the fact the TSPs and DPs are not required to have voice communication facilities with the RC per IRO-002-4, which implies that the only method for communication of Operating Instructions with TSPs and DPs would be in a written form. Please clarify if that was the intent of the SDT? In addition, TSPs are not required to have data links with the RC. With no required voice or data links what is the expectation for TSPs to receive Operating Instructions from the RC?
No
1)R4: Recommend replacing "to determine any potential System Operating Limit…" with "to determine any existing (pre-Contingency) and potential (post-Contingency) System Operating Limit… ". This change would be consistent with the terminology used in the proposed definition of Real Time Assessment. 2)R5: Recommend establishing a bright line criteria, such as: "fully redundant" and "a highly reliable infrastructure with end-to-end availability in each system of

95% or greater." Also recommend technical guidance to provide more clarity on the intent for monitoring alarm management and awareness systems. As written, R5 does not meet the quality criteria of clear and unambiguous language (as identified in NERC's "Acceptance Criteria of a Reliability Standard: Quality Objectives", item 8). From a compliance and enforcement perspective it is difficult to measure "giving particular emphasis" and "highly reliable infrastructure".
No
1)R3: Recommend replacing "to address potential System Operating Limit…" with "to address any anticipated (pre-Contingency) and potential (post-Contingency) System Operating Limit…". This change would be consistent with the terminology used in the proposed definition of Operational Planning Analysis. 2)R4: From the compliance and enforcement perspective it is important to know if the RC is required to notify impacted entities on a daily basis for Operating Plans that have extended impact (e.g. An Operating Plan based on an outage lasting a week) or just at the beginning? What is the intent of the SDT?
No
1)General: Recommend adding a Requirement 4 for RCs stating the RC shall notify entities that provided data per R2 when submitted data does not meet the specification and the nature of the deficiency. 2)R1: Use of the word "Provisions" in 1.2 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for TOP-003-3, R 1.2)
No
1)R1: Use of the word "Provisions" in 1.6 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a conference bridge) for conduct weekly conference calls? Or is it meant that the RC shall identify how the calls will be scheduled and conducted? If the latter, the word "provisions" should be replaced by "specifications". 2)R4: R4 seems to contradict R1. R1 requires each RC to have Operating Procedures, Processes or Plans for actions that may impact other RC areas; including provisions for weekly conference calls. R4 limits the requirement for RCs to participate in weekly conference calls to other RCs within the same Interconnection. Is it the SDT intent to have RCs have weekly conference calls with other RCs in the same Interconnection only? We recognize this may not be an issue outside of the ERCOT region, but we seek clarification from the SDT. 3)R's 6, 7 and 8: Requirements 6, 7 and 8 seem to exclude the situation where RCs agree. All the same actions should be taken for 6, 7 and 8 regardless of whether RCs agree or disagree on the existence of an Emergency. 4)R8: The purpose of the standard is to preserve the reliability benefits of interconnected operations. As such, for R8, each RC's implementation of another RC's action plan should have a required time frame. In addition, if the RC does not implement the action because such actions violate safety, equipment, regulatory or statutory requirements they should be required to notify the RC who developed the action plan within a required time frame.
Yes
1) R 1.3: "Reliability Coordinator Wide Area" is not a defined term. Recommend removing the word "Wide" and use the defined term of Reliability Coordinator Area.
No
1)R1: The use of the defined term "Transmission Operator Area" in R1 and R10 may lead to potential conflicts and reliability gaps. Transmission Operator Area is defined in the NERC glossary as "The collection of Transmission assets over which the Transmission Operator is responsible for operating." Transmission is capitalized indicating the following NERC glossary definition, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Using these definitions in the requirements may create a reliability gap if a TOP determines that generation, LSEs or DPs are not included in the Transmission Operator Area because they don't meet the definition of Transmission. In the ERCOT region where we have had TOP entities make the argument that generation units are not in their Transmission Operator Area and therefore they were not required to monitor those facilities. Similarly, it could be argued that ERCOT as a TOP does not "operate" any transmission assets. In the ERCOT region, a Coordinated Functional Registration is required between ERCOT and 15+ utilities to clarify the responsibilities of the TOP Function. Would the SDT consider adding technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area. Clearly, R3 requires BAs, GOPs, DPs and LSEs to comply with Operating Instructions issued by its TOP but there appears to be a risk that a TOP may not issue an Operating Instruction to an entity they do not consider within their Transmission Operator Area due to the definition. 2)R4: Recommend adding the following additional language behind the sentence in R4: "The instructed Entity will inform the TOP within 30 minutes of determining that it would not be able to or failed to carry out the Operating Instruction." If an Operating Instruction cannot be followed by the instructed entity, the TOP needs to be informed of the situation in time for the TOP to react accordingly for the continued reliability of the BPS. Adding the stated time horizon will add another measure to R4. 3)R6: Recommend adding the following language at the end of the Requirement: "citing one of the specific reasons shown in Requirement R5." This will be consistent with R4 referencing R3. 4)R8: Recommend adding the following language at the end of the Requirement: "The TOP shall inform the Entities of these issues within 30 minutes of determining that its actual or expected operations that result in, or could result in, an Emergency." The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, communication of actions taken or expected actions that may result in and emergency should be communicated before that emergency

occurs. As written the TOP could be compliant by informing the Entities well after the potential or actual emergency has occurred. 5)R9: Recommend adding "within 30 minutes" between "shall notify" and "its Reliability Coordinator". This will help assure that notified entities will have time to appropriately respond. The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. R9 has no stated time horizon for notification. As written the BA and TOP could be compliant by informing the RC (and other impacted interconnected entities) well after the potential or actual emergency has occurred. 6)R9: Recommend excluding "negatively" and "interconnected" and simplifying to "impacted" entities to be consistent with TOP-002-4 language. And to reflect that entities that are not “interconnected” can be impacted by outages of the equipment mentioned in R9. 7)R15: Recommend adding "within 30 minutes of having completed actions, provided the TOP is capable of reporting the actions" between "shall" and "inform its Reliability Coordinator". The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, the RC must have up to date information concerning actions taken within its area to perform its reliability responsibilities.
No
1)R2: R2 should be explicit on the time frames that an SOL exceedance must be mitigated within TOP Operating Plans. Recommend adding language from or referencing the SOL Performance Summary, Figure 1 from the Project 2014-03 SOL Exceedance White Paper. The concept contained in the SOL whitepaper is clear but it must be transferred to the Operating Plan development process to ensure that SOLs are mitigated in the appropriate time frame to avoid any thermal or stability limit violations. 2)R4: Recommend adding a new BA requirement to have an Operational Planning Analysis (in line with R1 language for the TOP). Currently it appears there is a gap for the BA responsibilities. The BA should also have a requirement for an Operational Planning Analysis in order to develop their Operating Plan for the next day. The NERC Functional Model lists BA responsibilities "ahead of time" for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as “The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ….” 3)R's 3, 5, 6 and 7: Requirements R3, R5, R6 and R7: Recommend adding language similar to this: “Such notification (Plan) shall be delivered before the start of the day to which it applies.” Requirements R3, R5, R6 and R7 require the TOP (R3 and R6) and the BA (R5 and R7) to notify either impacted NERC registered entities or the RC but no time frame for when the notification must occur. The reliability benefit of these deliveries is much reduced if they are made too late for appropriate actions to be taken by the receiving entities.
No
1)General: Texas Reliability Entity disagrees with use of the phrase "specification for the data necessary" in the Requirements of this standard. This phrase appears to meet the definition of the so-called "fill-in-the-blank" standards that FERC and the industry are seeking to avoid. NERC's Work Plan for Addressing Fill-In-The-Blank Reliability Standards (October 4, 2006) defines fill-in-the-blank standards as "…those that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the regions." This standard as written does exactly that: depends on regional criteria or procedures not currently in standards that are needed for an entity to achieve compliance. This standard does not meet the following criteria identified in NERC's Quality Objectives: clear and defined performance requirements, measurable, complete and self-contained standards and consideration of comments. The SDT addressed multiple commenters who expressed concern with the phrase "specification for the data necessary" during the comment period for TOP-003-2 under Project 2007-03 with the following: "The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made." The response indicates that the SDT may not have fully considered the concerns that were raised by the lack of specificity within the standard as currently written. While Texas RE understands the SDT is trying to allow flexibility to determine what data they need to perform their duties, there must be a minimum set of data that each TOP and BA needs to adequately fulfill their operational and planning responsibilities, therefore contributing to the reliability of the BPS. Recommend expanding R 1.1 and 2.1 to include a list of "at a minimum, data specification must include…" applicable to what the TOP and BA respectively need to perform their functions. Alternatively, recommend adding technical guidance similar to recently FERC approved MOD-032-1, Attachment 1 and application guidelines to include the types of data that must be provided by each TOP, BA, GO, GOP, IA, LSE, TO and DP as required in R5. 2)R1.1: Recommend enclosing in commas and moving the phrase “needed by the Transmission Operator” to before “sub-100”. The phrase “needed by the Transmission Operator” is positioned wrong to be clearly understood as applying to the “including sub-100 kV data and external network data” portion of the Requirement. It appears in the paragraph as a modifier that applies to the entire list of data and information. 3)R 1.2: The meaning of the word "Provisions" is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for IRO-010, R 1.2) 4)R2: Recommend replacing “analysis functions” with “Operational Planning Analysis”. It appears there is a gap for the BA responsibilities. Under the Functional Model, the BA is responsible ahead of time for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as “The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ….” 5)R3 and R4: Recommend adding the word "current" in front of

"data specification" to account for the possibility that the data specification can change. For example if the specification is changed from average MW capability for the year to the summer rating then the revised (or "current") data specification must be distributed to entities that have data required by the TOP (R3) or the BA (R4).
SDT, please consider that a different periodicity may be required depending on the tools used to perform Real-time Assessments. In the ERCOT region, some of the tools used for performing Real-time Assessments only run once every 30 minutes. Since SOLs, by definition, include voltage and transient stability ratings, this implies that the stability analysis should be conducted at least once every 30 minutes. If the tool fails to solve or fails to converge during one of these runs, would that constitute a violation of this requirement? If State Estimator or Contingency Analysis tools are unavailable for 30 minutes or more (i.e. currently a reportable event under the NERC Events Analysis program category 1h), would that constitute a violation of this requirement?
Yes
1)Operational Planning Analysis definition: Recommend returning the phrase "may be performed either a day ahead or as much as 12 months ahead" to the proposed definition of Operational Planning Analysis. That language includes the full Operations Planning horizon, not just next day. The current effective definition contains that phrase. Development of an Operating Plan to address the exceedances of SOLs/IROLs may take longer than one day to develop, so it is necessary to have a requirement to perform an Operational Planning Analysis for the full Operations planning horizon. The proposed definition, in conjunction with TOP-002-4 R1 which directs TOPs to have an Operational Planning Analysis for the next day to assess whether there will be a SOL exceedance, doesn't account for the time frame from after one day up to 12 months. 2)There is a discrepancy between the definition of "operations planning horizon" in the Project 2014-03 SOL Exceedance White Paper and IRO-017-1. The white paper defines operations planning time horizon as "operating and resource plans from day-ahead up to and including seasonal." IRO-017-1 (Note on part 1.5) defines the operations planning horizon as "next-day to one year out."
Group
ISO/RTO Standards Review Committee (SRC)
Greg Campoli
Yes
No
R1 and R2 appear redundant to the COM-001 Standard; suggest deleting these. We agree that a better distinction is required between voice and data requirements. However it should be added to COM-001 or remove COM-001. R4: The “Rationale” for the new R4 as being responsive to the NOPR where the Commission indicates “the reliability coordinator’s monitoring of SOLs provides a necessary backup function to the transmission operator….” However, other functional entities are not “backed up” and EOP-008 now contains backup provisions for reliability: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost.” R5 contains some ‘how, not why’ language: “giving particular emphasis to alarm management and awareness systems, automated data transfers,” which may, in fact, produce a lowest common denominator approach to EMS systems and a part of the Requirement is also redundant to COM-001: “over a redundant and highly reliable infrastructure.” R5 - Terms like “particular emphasis” and “Highly reliable” are not defined terms. They should be deleted or the requirement should include defined values for them for clarity.
No
We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word “Emergency”. The Rationale box suggests that the language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word “Emergency” is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addressed as soon as possible without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to “Emergency”, which should be corrected. Comment on R1: Replace ‘or’ with ‘and’. Comment on R5: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications, specifically a contingency analysis tool. R2 - The concept of an RC review of each TOP and each BA’s OPA seems questionable from a practical perspective. M2 requires proof of such an action. While RCs may indeed screen some of the more important OPAs, why must the RCs look at them all? And worse, why must that proof be retained?

No
We agree with the proposed changes, but are unable to locate R1, Part 1.7 as indicated in the Rationale box above R1, that: “Proposed Requirement R1, part 1.7 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.” We are therefore uncertain as to how the concerns raised in Paragraph 92 (and in the next several paragraphs) of the FERC NOPR are addressed.
No
R2 and 4, as well as the portion of 1.1, which indicates, “and the process to follow in making those notifications” are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
No
R2 VRFs should be Medium, not Low. (note: CAISO does not agree with this comment). Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it’s the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC: - Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.
No
Regarding R2, did the SDT consider whether putting a “transmission operations” requirement on a Balancing Authority was appropriate? We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that “Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.” This requirement seems out of place. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP’s and OC’s recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator (in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest removing the BA from R7. Requirement R9 stipulates that: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” The last part appears to be unclear as the “affected entities” can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the “associated communication channels between affected entities” will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to “between it and the affected entities”. Requirement R11 is out of place for the similar reasons indicated for R2, above. We suggest removing this requirement, or move it to the appropriate BAL or EOP standard. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart. Comments R1: We do not agree with the rationale for this requirement. If an RC does not act he will be in violation of other requirements and therefore a possible double jeopardy. The previous requirement R3, obligated an RC to have authority from someone to ensure that they could take actions which is now absent. Comment R7: We believe the previous language should be retained to limits the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. Comment R8: Should remove “or could result in” since it is unmanageable to inform all possibly impacted entities of all possible contingencies. Comment R9: How does one access a potential negative impact? To what extent would negatively impacted entities need to be notified? Could it involve even governor response? Also, is this for planned or actual outages? The measure states planned, the requirement doesn’t. How will this coordinate with COM-001 R3? Comment R10: The phrase ‘including sub-100 kV’ is not needed. If the sub 100 kV facility impacts the BES in such a manner, it should be labeled a BES facility per the inclusions in the new definition. Comment R13: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications specifically a contingency analysis tool. How is this coordinated with EOP-004 for reporting tool outages exceeding 30 minutes?
No

Requirements 6 and 7 are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
Yes
We agree with all the elements in the standard except the VSL for R5. Please see our comments under Q14, below.
No
We agree with all the proposed retirements except TOP-004-2, Requirement R4. R4 stipulates that “If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.” While the intent is covered by the revised definition for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, neither definitions specifically ask for the verification of existing SOLs/IROLs or the determination of valid SOLs/IROLs as system condition changes go beyond the conditions covered by previous SOL/IROL calculations. Requirement R4 thus should be retained (and mapped into TOP-001-3) unless the two definitions are revised to require the verification/determination of SOLs/IROLs through Operational Planning Analysis and Real-time Assessment. Not retaining R4, or without changing the definitions for the two terms, a responsible entity may project or enter an unknown state (for which valid SOLs/IROLs may not exist). An Operational Planning Analysis and Real-time Assessment at this time may indicate expected system performance, which may be unacceptable from an equipment loading, voltage level or stability viewpoint, but still there exist no SOLs/IROLs as a target to guide the responsible entity to adjust the BES to arrive at an acceptable state.
Yes
From an operational perspective, we do not believe it is practical to cover for any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operation plans must protect against that. We also have a concern over the actions depicted for the Emergency (4 hr) condition in the example in Table 1. When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with the time on which the applicable emergency rating is based (e.g. 30 or 15 minutes) to reduce flow within the applicable rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency rating consistent with timelines identified in Operating Plan. The “as necessary and appropriate” qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the Emergency rating.
No
Please reference above comments regarding individual draft standards. In addition, we offer the following comments: a. IRO-008-2, R6: The LOWER VSL which makes reference to “Emergency” should be changed to “anticipated or actual SOL/IROL exceedance”. Please see our comment under Q3, above, for details. b. IRO-010-2, R1: The SEVERE VSL for R1 can be reworded to “The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.” Since there are only 4 parts in R1 and hence the “four or more” is inappropriate. c. IRO-017-1, R1: We do not believe the VSL for R1 should not be binary. R1 requires the RC to identify the roles and develop a process for coordinating outage plans, the latter to include several elements. It may well be a case where the RC did develop the process but missed some of the elements listed in Parts 1.1 to 1.4. For example, a LOWER VSL may be assigned if the RC did develop identify the roles and develop the process document, but missed one of the parts in 1.1 to 1.4. A MEDIUM VSL may be assigned if the RC missed two of the parts, etc. We suggest the SDT to review the VSL development guideline and FERC’s guideline, and revise the VSL for R1 accordingly. d. TOP-001-3, several requirements: Since we disagree with a number of requirements in this standard, we are unable to support the VSLs associated with these requirements. e. TOP-003-3, R5: This requirement contains 3 parts each of which specifies a particular aspect of data provision. It is conceivable that a responsible entity provided data as specified in R3 and R4 but failed to follow one or more of the specific format, process or protocol as depicted in Parts 5.1 to 5.3. Hence, having a binary VSL for R5 would imply that failing to meet just one of Parts 5.1 to 53 will render the responsible entity being assessed a SEVERE violation. This is inconsistent with the VSL guideline. We suggest the SDT to expand the VSL for R5 to cover the cases of failing to meet one and two of the three parts in R5.
No
Group
Peak Reliability
Jared Shakespeare
Yes

No
• R1: What is the definition of “voice communication facilities”? Is a list of phone numbers and a phone system sufficient? • R2: “Data link” is not a defined term. “As required for reliable operations in the Interconnection” should be added to R1 and R2. RC data links with TPs, PCs, GOPs, LSEs, and DPs are not required for reliable operations. It is sufficient for the RC to have data links with BAs and TOPs, and get TP/PC/GOP/LSE/DP data from BAs and TOPs. • R3: The word “approve” should be changed to “disapprove”. System Operators may not always have the understanding of the maintenance to actively “approve” it, but their authority should be to disapprove planned tool outages if they will adversely impact real-time operations or if System Operators need more time to assess a tool outage. • R4: The way it is phrased gives risk for misunderstanding. Is the Requirement that RCs must “monitor” the status of RAS? Or is the Requirement that the RC must understand/model the impact of the RAS so that the RC knows the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The way it reads it seems the RC is only required to “monitor” the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the RC needs to monitor facilities in adjacent RCs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase “as needed” to “and neighboring Reliability Coordinator Area” adds more clarity.
Yes
• R1 – “…planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area” should be “planned operations in its Wide Area for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Area” • R5: Language should be added to this Requirement to allow for tool outages. Adding “when tools are operating as expected” is an option. • R7: this Requirement is duplicative of IRO-001-4 R1. Although R7 is more specific than IRO-001-4 R1, R7 is covered by IRO-001-4 R1.
Yes
• R1.1: Does “external data” mean one RC has the authority per this Requirement to request data from another RC? • R2: The “mutually agreeable” language is potentially problematic, as it is unclear how the RC will receive the data if they cannot reach agreement on the format. Using “a clearly defined format” would be better. • IRO-010-1a had a very important statement in R1.4 – “Process for data provision when automated Real-Time system operating data is unavailable.” That is important to have a common understanding of expectations and a plan for data delivery even when the automated system is unavailable. This should be added back to the Standard.
Yes
• R1.6: “Provisions for weekly conference calls” should be “Provisions for weekly conference calls with Reliability Coordinators within the same Interconnection” to match the language of R4. • R2: The current Standard allows for 36 months. It is unclear why this changed. There doesn’t seem to be a reliability issue that would precipitate this change. Also, R2.2 should be changed to language consistent with EOP-006-2 R2 & R4. • R5 & R7: “Each Reliability Coordinator that identified an Emergency” should be changed to “Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area” If one RC identifies and Emergency in another RC’s Area, and there is disagreement, the first RC should not be required to develop a plan. • R9: “unless such actions cannot be physically be implemented or would violate safety, equipment, regulatory, or statutory requirements” should be changed to “unless such actions would cause adverse reliability impacts or would violate safety, equipment, regulatory, or statutory requirements”.
Yes
• R1.3: “Reliability Coordinator Wide Area” should be “Reliability Coordinator’s Wide Area”
Yes
o R1, R2: There is a potential conflict arising between a BA and TOP (when the two are not the same company) where a TOP may issue an Operating Instruction to a BA to shed load or bring up generation and at the same time a BA may issue a directive to the TOP to trip/restore a line for potentially the same reliability issue. Will both be required to follow each other’s directives? o R10: The way it is phrased gives risk for misunderstanding. Is the Requirement that TOP must “monitor” the status of RAS? Or is the Requirement that the TOP must understand/model the impact of the RAS so that TOPs know the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The way it reads it seems the TOP is only required to “monitor” the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the TOP needs to monitor facilities in adjacent TOPs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase “as needed” to “and neighboring Transmission Operator Area” adds more clarity. o R11: “including the status of Special Protection Systems” should be “including the status and impact of Special Protection Systems”
Yes
• R4.3. Does “demand pattern” simply mean a load forecast? If not, it should be clarified. If so, it should say “load forecast” as this term is more widely understood and used in the industry.
Yes
• R5: The IA should be removed. In the INT Re-write project, all operational requirements on the IA were removed and put on the sink BA. Consistent with that, the IA should be removed from this Requirement. • R5: The “mutually

agreeable" language is potentially problematic, as it is unclear how the entity will receive the data if they cannot reach agreement on the format. Using "a clearly defined format" would be better.
Yes
Yes
• TOP-004 R5 – The requirement being retired deals with separation, but the mapping document references load shed language from the Functional Model. Separation may occur without load shed, so it is not clear that the coordination of separation is completely covered. • TOP-008 R1 – The requirement being retired has the language "or contributing to an IROL or SOL violation", and the requirements in the mapping document may be missing coverage for SOLs outside of the TOPs area.
Yes
• Peak Reliability believes this timeframe to be sufficient as long as the 30 minutes is under normal operating conditions (when tools are working as expected). However, IRO-008-2 R5 needs to be revised to include language allowing for tool outages. What is the SDT's expectation of performing Real-Time Assessments when tools are unavailable due to unforeseen tool outages?
Yes
o Comment 1 – the SOL performance summary states that it is acceptable to operate above the highest available limit post-contingency as long as "the entities operating plan address potential impacts and mitigating strategies to ensure potential impact is localized." Post-contingency exceedance of the highest available limit should not be allowed unless there are no viable pre-contingency actions short of load shed, AND the impact of the contingency is known to be contained. o Comment 2 – Operating plan example table uses the term "load shed" to describe a facility rating. This sounds like it came from Alstom data base naming conventions, but may result in confusion and should be changed.
Yes
Yes
• Operational Planning Analysis proposed definition should address the modeling of impacts of sub-100 kV and SPS/RAS – not just the status of SPS/RAS. Also "The evaluation shall reflect inputs" should be "The evaluation reflects inputs" to avoid the appearance of having a Requirement within a definition.
Individual
Jason Snodgrass
Georgia Transmission Corporation
No
(1) GTC does not believe that the DP should be an applicable entity to this standard. The RC would not direct a DP to perform Operating Instructions due to the proper chain of command. The RC would first direct the TOP. See RC section in the NERC Functional Model under System restoration actions "The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authorities." Due to this proper chain of command, there is no reliability gap between the RC and the DP. The TOP, could further direct Operating Instructions during an Emergency to the DP per TOP-001-3. If the SDT does not remove the DP from applicability to this standard, then GTC recommends the following: (2) The current proposal for R2 as written could overly expose the DP to excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment "affecting the reliability of the BES" is not very routine. GTC believes the intent of this requirement for the DP should complement COM-002-4 R6 relating to Operating Instructions during an Emergency "affecting the reliability of the BES". The use of the NERC term "Emergency" would capture this intent. GTC proposes the language "[during an Emergency]" be added after "….shall comply with its Reliability Coordinator(s) Operating Instructions [ ] ".
No
GTC supports the comments provided by GSOC for this question.
GTC supports the comments provided by GSOC for this question.
No
(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.
Yes
No

GTC agrees with its RC that this standard is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary, which is current day and next day operations. As written, this requirement conflicts with the Functional Model and the NERC Glossary, which both clearly address the roles of the Reliability Coordinator. The Reliability Coordinator, according to the Functional Model, “receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.” Furthermore, the NERC Glossary notes that the Reliability Coordinator “is to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.” This definition indicates that the Reliability Coordinator’s scope is for next day and real-time operations. GTC recommends that this standard be withdrawn from the project. If the SDT does not withdraw the standard, at a minimum, the SDT should modify the standard to address the following comments. The proposed subpart 1.5 requires RCs to document and maintain the specifications for outage analysis during the operations planning horizon, which is next day to one year out. GTC recommends adding language to subpart 1.5 to clearly state that the RC has discretion by adding “, if deemed necessary by the RC” to the end. GTC does not agree with R3 or R4 as it seems to imply that RCs conduct outage coordination assessments even beyond the operations planning horizon. Again, RCs are focused on real time and next day timeframes, not the Planning Assessment timeframe (Years 1 through 10), and should not be required to coordinate solutions in the Planning Assessment timeframe. Nor should the PC/TP be required to provide its Planning Assessment because RC will not be impacted. This requirement is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary (see definition of RC), which is current day and next day operations. This requirement should be removed, or, at a minimum, be revised to include “if deemed necessary by the RC”. NOTE: The existing TOP-002-2.1b R11 requires TOPs to perform seasonal studies to determine SOLs and to provide the results of those studies to its RC.
No
(1) Purpose: Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, GTC believes the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other Standards closely associated such as COM-002-4. Specifically GTC recommends replacing the terms “reliability of the Interconnection” with the terms “reliability of the Bulk Electric System (BES)”. (2) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment “affecting the reliability of the BES” is not very routine. GTC believes the intent of this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. The use of the NERC term “Emergency” would capture this intent. GTC proposes the language “[during an Emergency]” be added after “….shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] ”.
No
GTC supports the comments provided by GSOC for this question.
No
(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.
Yes
We agree with the retirement of the above mentioned standards.
Yes
We agree with the retirement of the above mentioned standards.
No
No
The bandwidth between “lower” and “severe” VSL is only 15 minutes. Expand bandwidth.
Yes
(1) GTC recommends that the drafting team post redlines with each standard, so it is easier to view the proposed changes. Having clean copies of the revisions only adds more time to have to track changes and it is a very inefficient use of industry’s time. (2) The drafting team should consider reducing the amount of information in the posting, or extending the comment period to allow for a thorough review by industry. We recommend holding a technical conference or a series of webinars (instead of just one) to go through each of the standards in detail. The amount of information cannot be covered in a single hour-long webinar. (3) Thank you for the opportunity to comment.
Individual
Joshua Andersen

Salt River Project
Yes
R3 requires an entity to cite one of the reasons in R2 for an inability to perform an Operating Instruction. SRP expresses concern over only permitting a predetermined list of rational for not performing an Operating Instruction. Situations may arise that do not fit nicely into one of the given reasons. IT is suggested to allow for other rational for not performing Operating Instructions.
Yes
Yes
This standard significantly increases the communications required from the RC on the results of data exchanges, Operational Planning Analysis results, etc. This increase in communication could cause confusion about what is a potential problem being communicated per the requirements or and what is a true real-time problem.
Yes
SRP suggests that the RC determines the data obligations listed in R3 Part 3.1, 3.2, and 3.3. The RC is making the request for data so they should provide the format they need the data. Furthermore, if this is determined between each entity and the RC there may be multiple different formats, processes for resolving data conflicts, and security protocols that the RC will need to coordinate. If the RC determines the obligations they would all align.
Yes
No
Per R1, the RC must develop an Outage Coordination process that will take many aspects out of the BA & TOPs hands, specifically flexibility for units or crews on their start and end times. This decreased flexibility can lead to increased costs. R3 is burdensome to provide textual summaries of load flow studies and the assessment information for those studies. There are also concerns over distributing assessment information externally. R4 requires the Transmission Planner to coordinate solutions for issues or conflicts with planned outages. Outage coordination can be managed by Transmission Operators. SRP suggests allowing for Transmission Operators to coordinate solutions with the RC and PC.
Yes
Yes
No
• R2 requires entities to provide a specification for all data necessary for analysis and real time monitoring which will result in a massive specification that could include all ICCP points used for modeling, dynamic signals & pseudo ties, BA tie lines, elements of NSI & NAI, SPS & RAS status & alarm points and a multitude of other data that may be required. The data required here is very dynamic and will change in a very short period of time. Any specification created initially to meet this requirement will very soon become outdated. • R2.3 requires a BA to review the periodicity for providing data. Does a BA need to review each data point and determine appropriate periodicity? Does this periodicity apply for a BA's internal data, external data, or both? With the scan rates already required in BAL-005-1b R8, why is this requirement necessary? • R2.4 references a respondent for data but does not specify who the respondent would be. • R4 requires BAs to distribute data specifications to other entities. For a BA with many adjacent entities, this will become a significant increase in workload and resources to distribute the specifications, and then document and maintain compliance evidence that this specification was received and that data was provided by each entity. This is burdensome and would only minimally increase reliability. A BA with several adjacent entities will need to negotiate a format, conflict resolution and security protocols with each individual entity per R5.1, R5.2, and R5.3. This will result in a significant number of individual agreements with each entity. Creating these agreements, maintaining these agreements and then maintain compliance evidence for each agreement is burdensome with only a minimal enhancement in reliability. SRP suggests the creation of a regional committee to address those conflicts in exchanging necessary operational data that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this standard
Yes
Yes
Yes
No

Yes
Yes
TOP-003-3 R5 does not adequately cover the planning aspects of TOP-002-2.1b R15. TOP-003-3R5 seems to be a “follow direction” requirement where TOP-002-2.1b is a planning requirement.
Individual
Rich Salgo
NV Energy
Yes
No
R2: Regarding data links with a variety of entities, we see no reliability rationale for requiring data links with Planning Coordinators, Transmission Planners, Load Serving Entities, or Distribution Providers. With the first two, there is no call for real time data; for the others the data for LSE and DP entities normally routes through the host TOP or BA, which is where the data link requirement should solely reside. Recommend deletion of “Load Serving Entities, or Distribution Providers.” R3: As written, it is unclear whether the authority to approve planned outage and maintenance of its monitoring and analysis capabilities extends to RC personnel other than the Operators alone. Also, the authority to approve does not literally mean that the RC Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without RC approval. R5: The phrase “over a redundant and highly reliable infrastructure” is rather imprecise. Suggest replacing this phrase with “over a system that is not interrupted by a single point of failure”.
Yes
No
In R2 and R3, there is no specificity as to the allowable time for an entity to satisfy a new or modified data supply specification from the RC. As well, there is lack of precision in the use of the term “mutually agreeable” in 3.1 to 3.3. We recommend allowance of a time period, perhaps 90-180 days, for an entity to become fully responsive to requests from the RC for new data or modifications to existing reporting requirements.
Yes
Most of these requirements are predicated on the idea that multiple RC entities exist within a particular Interconnection. Accordingly, most of the requirements will be inapplicable to the WECC and TRE areas.
No
R3 and R4: The Planning Assessment is being introduced as a coordination tool for communication to the RC in R3, and coordination actions pursuant to the Assessment are specified in R4. Given that the RC operates in the Operations Planning and Real-Time environment, yet the Planning Assessment is a long term planning instrument, we do not believe that this coordination is applicable or useful. Rather, the RC should be seeking next-day assessments from the TOP entities within its footprint. Suggest removal of these requirements.
No
R1 and R2: The requirement to act or direct others by issuing Operating Instructions calls into question the ability of a TOP or BA to demonstrate in all cases that Operating Instructions were issued. Would this require the logging and retention of records for each and every Operating Instruction given by a TOP or BA? If so, the volume could easily exceed hundreds of documented Operating Instruction exchanges per day. Also, we recommend changing the phrase “to address its reliability functions” to “to maintain system reliability”, as this is more precise and descriptive of the rationale for action. R3 and R5: We note that pending the final definition of Operating Instruction, there may be a significant number of Operating Instructions for which an entity will be required to maintain documentation. R7: The term “assist” is used in describing the required action in response to a requestor. This term is sufficiently vague and ambiguous; therefore, we suggest the use of examples or parameters be provided around the term “assist” in order to clarify the intent and scope of the assistance. Perhaps add clarifiers like “such as delivery of energy, adjustment of reactive power supply or absorption, use of controllable devices, etc.” R10: This requires the monitoring of facilities within its TOP area and neighboring TOP areas, including sub-100 kV facilities needed to maintain reliability and the SPS within its TOP area. This reaches prescriptively into the realm of the neighboring TOP’s without specifying the degree of monitoring required or whether this is limited to immediately adjacent TOP’s or all TOP’s “in the neighborhood”. I would suggest limitations be placed on the scope of this requirement, as it significantly expands the monitoring task and the demonstration of compliance, and worse, it runs the risk of causing the TOP to lose focus on his own operating area. While there is some merit in operator view into adjacent systems, the wide area view suggested by this requirement is more applicable to the functions of an RC. R9: Recommend that R9 read as: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between such entities.” R13: The requirement to perform a Real-Time Assessment once every 30 minutes is onerous

and goes beyond the directive findings of the SW outage event. Recommend the use of a performance-based requirement rather than a rigid requirement to conduct at least 48 assessments each day. The goal ought to be that the Operator is continuously aware of the impact of any contingency upon the system, not that the assessment is performed on a 30 minute basis. What allowance is provided for loss of contingency analysis tools? Such loss is a reportable event, yet under this requirement it also becomes a violation if not restored and satisfactorily executed within 30 minutes. R14: This requirement compels the TOP to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-Time Assessment or real time monitoring. The requirement is unacceptably open-ended and does not specify the time frame for such initiation, or even what it means to “initiate” its plan. We suggest specificity be added by the SDT in the text of this requirement. R15: The requirement to “inform” the RC of actions to return the system to within limits also lacks specificity as to the time frame to inform, and the allowable means to inform. As well, it is left to interpretation whether the "actions to return the system to within limits" are those that have been taken or those that will, or could be, taken. We suggest clarification of intent on this requirement and the allowance that electronic SCADA information will satisfy the duty to inform. R16 and R17: The authority to approve does not literally mean that the BA/TOP Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without BA or TOP approval. If the intent of the SDT is not met here, clarification is necessary to ensure that all such work must first be approved by the BA/TOP Operator.
No
R1: Requires that the TOP shall have an OPA that will allow it to assess whether planned operations for the next day within TOP area will exceed any SOLs. This requirement fails to acknowledge that the “next day” for some OPAs will be several days in the future and not the immediately following day. Without that provision, it would mean that next day analyses must be conducted 365 days per year (if it only is valid for the “next” day). We suggest that the language be rephrased as follows: “…that will allow it to assess whether its planned operations for the Operations Planning horizon within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).” R2: Same issue as with R1. Suggest changing the time frame of the Plan to be the Operations Planning horizon. R3: As stated, each TOP shall notify impacted NERC registered entities identified in the Operating Plan cited in R2 as to their role in the Plan. Suggest clarifying language inserted as follows “to the extent that any NERC registered entities are impacted” to allow for the likelihood that none are impacted. The requirement of notifying “four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s)” is vague and potentially unenforceable. Suggest the SDT drop the four or more than 15% for “notify adjacent negatively impacted NERC registered entities”. Is posting of the guide on the Region's web-site sufficient? If not, how do we define 15% of the impacted entities? R4: Here the BA shall have an Operating Plan. This has the same time frame issue as with R1 and R2, and we propose similar resolution.
No
R1 and R2 represent a significant documentation effort on the part of TOPs and BAs. It is supportable as written, but it will require a significant effort within typical grid operations staff to maintain the data specification and process the interactions with the entities who will be supplying the data. R3 and R4 should be clarified as: “Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment”. This will limit the specification to only that data which is needed for these analyses, monitoring and assessments.
Yes
Yes
No
As noted in comments to prior questions, the 30 minute periodicity is inappropriate. As noted earlier, we believe that the intent here should be that the Operator has situational awareness, not that one meets a quota of RTA executions. The 30 minute period is also in conflict with certain EOP requirements which allow up to 2 hours to reestablish control center functionality. Further, a 30 minute requirement would almost necessitate backup means of conducting RTAs, as there is little tolerance for a failure of the tools.
Individual
Terry Harbour
MidAmerican Energy
No
No
Comments: R2: Regarding data links with a variety of entities, there isn’t a reliability rationale or need for requiring data links with Planning Coordinators, Transmission Planners, Load Serving Entities, or Distribution Providers. With the first

two, there is no call for real time data; for the others the data for LSE and DP entities normally routes through the host TOP or BA, which is where the data link requirement should solely reside. Recommend deletion of “Load Serving Entities, or Distribution Providers.” R3: As written, R3 is unclear whether the authority to approve planned outage and maintenance of its monitoring and analysis capabilities extends to RC personnel other than the Operators alone. Also, the “authority to approve” should not literally mean that the RC Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without RC approval. Suggest changing to authority to approve is changed to authority to “deny”. R5: The phrase “over a redundant and highly reliable infrastructure” is imprecise. Recommend deleting “over a redundant” in order to remove the similar language and remove the possibility of double jeopardy. Concerning the word of “highly reliable infrastructure”, we do not believe that an RC would utilize “slightly reliable infrastructure”. This ambiguous wording is subjective. Recommend deleting “highly reliable infrastructure”. If “highly reliable infrastructure” is not deleted, suggest replacing this phrase with “over a system that is not interrupted by a single point of failure”.
No
Specific to IRO-008-2, R5, MidAmerican is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. MidAmerican recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
No
In R2 and R3, there is no specificity as to the allowable time for an entity to satisfy a new or modified data supply specification from the RC. As well, there is lack of precision in the use of the term “mutually agreeable” in 3.1 to 3.3. This is too vague and therefore relatively unenforceable. Also suggest a time period of “at least annually” for entities to develop processes and respond to new or modified data requests. If entities cannot respond within one calendar year but in less than 15 months, an entity should develop a mutually agreeable mitigation plan.
Yes
No
In R3 and R4, the Planning Assessment is being introduced as a coordination tool for communication to the RC in R3, and coordination actions pursuant to the Assessment are specified in R4. The RC operates in the Operations Planning and Real-Time environment, while the Planning Assessment is a long term planning instrument. This coordination is not applicable or useful. Rather, the RC should be seeking next-day assessments from the TOP entities within its footprint.
No
R1 and R2: The requirement to act or direct others by issuing Operating Instructions calls into question the ability of a TOP or BA to demonstrate in all cases that Operating Instructions were issued. Suggest that specific compliance wording be added to the requirement and or measure to indicate that “entities be able to show evidence of a process (not evidence to every instruction) to comply with each Operating Instruction issued…”. Otherwise this could require the logging and retention of records for each and every Operating Instruction given by a TOP or BA. Also, suggest changing the phrase “to address its reliability functions” to “to maintain system reliability”, as this is more precise and descriptive of the rationale for action. R3 and R5: We note that pending the final definition of Operating Instruction, there may be a significant number of Operating Instructions for which an entity will be required to maintain documentation. R7: The term “assist” is used in describing the required action in response to a requestor. This term is sufficiently vague and ambiguous; therefore, we suggest the use of examples or parameters be provided around the term “assist” in order to clarify the intent and scope of the assistance. Perhaps add clarifiers like “such as delivery of energy, adjustment of reactive power supply or absorption, use of controllable devices, etc.” R9: It isn't clear how entities will notify “its Reliability Coordinator and at least 15% of negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities”. How was the 15% threshold selected? The phrase “negatively impacted interconnected NERC registered entities” is vague and therefore unenforceable. The SDT should consider modifying R9 to read “notify the RC and any adjacent NERC registered negatively impacted entities.” R10: This requires the monitoring of facilities within its TOP area and neighboring TOP areas, including sub-100 kV facilities needed to maintain reliability and the SPS within its TOP area. This reaches prescriptively into the realm of the neighboring TOP’s without specifying the degree of monitoring required or whether this is limited to immediately adjacent TOP’s or all TOP’s “in the neighborhood”. I would suggest limitations be placed on the scope of this requirement, as it significantly expands the monitoring task and the demonstration of compliance. Only the RC has the appropriate “wide-area view” to meet R10. The TOP must remain focused on its own area. The RC is the appropriate entity for spanning multiple TOP’s. R13: The requirement to perform a Real-Time Assessment once every 30 minutes is onerous and goes beyond the directive findings of the SW outage event. Recommend the use of a performance-based requirement rather than a rigid requirement to conduct at least 48 assessments each day. The goal ought to be that the Operator is continuously aware of the impact of any contingency upon the system, not that the assessment is performed on a 30 minute basis. What allowance is provided for loss of contingency analysis tools? Such loss is a reportable event, yet under this requirement it also becomes a violation if not restored and satisfactorily executed within 30 minutes. R14: This requirement compels the TOP to “initiate” its Operating Plan to

mitigate a “real-time” SOL (not a RTCA calculated) exceedance identified as part of its Real-Time Assessment or real time monitoring. The requirement is vague, potentially unenforceable, and unacceptably open-ended. It does not specify the time frame for such initiation, or even what it means to “initiate” its plan. We suggest specificity be added by the SDT in the text of this requirement. R15: The requirement to “inform” the RC of actions to return the system to within limits also lacks specificity as to the time frame to inform, and the allowable means to inform. As well, it is left to interpretation whether the actions to return the system to within limits are those that have been taken or those that will or could be taken. We suggest clarification of the intent by adding examples through wording (such as via SCADA or emails, or voice communications). SCADA should be an acceptable way to inform the RC. R16 and R17: The authority to approve does not literally mean that the BA/TOP Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without BA or TOP approval. If the intent of the SDT is not met here, clarification is necessary to ensure that all such work must first be approved by the BA/TOP Operator.
No
R1: Requires that the TOP shall have an OPA that will allow it to assess whether planned operations for the next day within TOP area will exceed any SOLs. This requirement fails to acknowledge that the “next day” for some OPAs will be several days in the future and not the immediately following day. Without that provision, it would mean that next day analyses must be conducted 365 days per year (if it only is valid for the “next” day). We suggest that the language be rephrased as follows: “…that will allow it to assess whether its planned operations for the Operations Planning horizon within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).” R2: Same issue as with R1. Suggest changing the time frame of the Plan to be the Operations Planning horizon. R3: As stated, each TOP shall notify impacted NERC registered entities identified in the Operating Plan cited in R2 as to their role in the Plan. Suggest clarifying language inserted as follows “to the extent that any NERC registered entities are impacted” to allow for the likelihood that none are impacted. The requirement of notifying “four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s)” is vague and potentially unenforceable. Suggest the SDT drop the four or more than 15% for “notify adjacent negatively impacted NERC registered entities”. Is posting of the guide on MISO web-site sufficient? If not, how do we define 15% of the impacted entities? R4: In R4, the BA shall have an Operating Plan. This has the same time frame issue as with R1 and R2, and we propose similar resolution. R5: R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities… Plus the notification of NERC Registered Entities identified in those plans. How does a requirement to inform someone of an Interchange schedule, that they established with you, promotes system reliability. Notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have a documented Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the Industry Experts Review Panel only recommends this and it is not a FERC directive.
No
R1 and R2 represent a significant documentation effort on the part of TOPs and BAs. It will require a significant effort within typical grid operations staff to maintain the data specification and process the interactions with the entities who will be supplying the data. R3 and R4 should be clarified as: “Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment”. This will limit the specification to only that data which is needed for these analyses, monitoring and assessments. This requirement will require attestations of compliance. Regulators have stated they will not accept attestations in the future.
Yes
Yes
No
See comments provided under TOP-001.
No
No
The VRFs and VSLs will need to be adjusted.
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes

Yes
Yes
Yes
No
Since this Standard only includes the operations planning horizon, BPA does not feel it is necessary or appropriate to include Planning Coordinator (PC) and Transmission Planner (TP) as applicable functions. BPA believes requirements R3 and R4 should be applicable to Transmission Operators (TOPs), but not TPs or PCs. BPA also feels that identifying Planning Assessment in this Standard creates a conflict by introducing the Planning Horizon into a Standard that should only cover an operations horizon. The Planning Assessments in TPL-001-4 are not the type of seasonal or outage planning assessments performed by TOPs. The TP would not be assessing planned outages in the Planning Assessment.
No
Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the Standard as an appendix. BPA believes the language in requirements R8 and R14 is too ambiguous and open-ended. As a result, this would likely lead to decisions based on assumptions. BPA suggests both requirements be tied to an operating procedure or process, which, in turn, can be left to each applicable entity to define. BPA also opposes language in the Standard which has the potential to conflate events that are happening with events that have a high probability of happening. BPA suggests the drafting team clearly separate these two concepts, and include parameters for possible events, so that applicable entities are not required to predict all possible future events.
No
Concerning R1, BPA suggests clarifying the conditions under which an entity is required to assess whether planned operations will exceed any of its SOLs. Without this clarification, it is unclear whether R1 requires assessing normal system conditions: N-1 or N-1-1. Regarding R4, BPA feels that, because of the time and effort needed for forecasting and analyzing all items included in its sub-requirements, the inclusion of R4.1 and R4.2, which are market-driven, leave insufficient time to complete an adequate assessment for the next day. BPA believes the Standard would be better supported should the word “addresses” be replaced with “considers.” BPA also suggests that the “evidence” mentioned in M4 is ambiguous and suggests rewording M4 to state, “Each Balancing Authority shall have evidence that it has developed a plan to operate to the safe and reliable operation of the BES.”
Yes
Yes
Yes
No
BPA proposes 60 minutes as the correct periodicity. This allows time to set up, run and analyze the results of studies, especially if stability analyses must be performed.
Yes
Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the TOP-001-3 Standard as an appendix.
No

Consideration of Comments

Project 2014-03 Revisions to TOP and IRO Standards

The Project 2014-03 Drafting Team thanks all commenters who submitted comments on the standards. These standards were posted for a 45-day public comment period from May 19, 2014 through July 2, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 71 sets of comments, including comments from approximately 186 different people from approximately 136 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the project page.

The SDT made changes to the following items in response to industry comments:

- **Definitions of Real-time Assessment and Operational Planning Analysis**:
  - Minor clarifying changes (see list of changes below for TOP-001-3 for details)
- **Proposed IRO-001-4**:
  - Requirements R2 and R3: deleted 'Transmission Service Provider' as it does not truly apply to these requirements
  - Measures and VSL language: revised as needed for consistency with requirement language changes
- **Proposed IRO-002-4**:
  - Requirement R1: deleted as it is redundant with proposed COM-001-2
  - Requirement R2: changed list of entities with whom the Reliability Coordinator is required to have data exchange capabilities, to show just Transmission Operator and Balancing Authority and other entities deemed necessary to allow for situations where a Reliability Coordinator exchanges data only with Transmission Operators and Balancing Authorities who in turn solicit information and data from other entities and relay it to the reliability Coordinator as well as situations where the Reliability Coordinator exchanges data directly to other entities
  - Requirement R3: added 'telecommunications' to provide System Operators the ability to control scheduling of planned telecommunication outages
  - Requirement R4: re-arranged the language to clarify the intent of what is to be monitored; clarified that sub-100 kV facilities are as identified as necessary by the Reliability Coordinator
  - Requirement R5: deleted 'and highly reliable' as unmeasurable
  - Requirement R2 VSL: changed from a binary (severe) to an incremental approach consistent with approved IRO-002-2, Requirement R1

- Measures and VSL language: revised as needed for consistency with requirement language changes

- **Proposed IRO-008-2**:
  - Requirement R1: Minor revisions to clarify the SDT's intent, including changing 'Reliability Coordinator Wide Area' to 'Wide Area'
  - Requirement R2: deleted as duplicative of Requirement R3 as the plans can't be coordinated unless they have been reviewed
  - Requirement R3: minor revisions for consistency
  - Requirement R4: deleted 'NERC registered' as a modifier of 'entities' as unnecessary
  - Requirement R5: changed language to 'ensure' that the Real-time Assessment is performed to acknowledge the situation where capabilities are unavailable and back-up methods are employed, or where an agreement for a third party to perform the Real-time Assessment exists
  - Requirement R7: deleted as duplicative with proposed IRO-001-4 Requirement r1
  - Data retention: changed from three months to 90 days for consistency; Requirement R5 and Measure M5 – changed to a rolling 30 day period consistent with approved IRO-008-1
  - Requirement R1 VSL: made minor grammatical corrections for consistency
  - Requirement R5 VSL: made consistent with approved IRO-008-1 Requirement R2
- **Proposed IRO-010-2**:
  - Effective date: changed first step from 10 months to 9 months to better align with possible approval dates
  - Requirements R1 and R2 VRF: changed from 'Medium' to 'Low' for consistency with approved IRO-010-1a Requirements R1 and R2
  - Requirement R2 VSL: added explanatory text as to the SDT intent on how to apply the VSLs
  - Requirement R3: deleted Planning Coordinator and Transmission Planner as those entities would not be involved in submitting data as envisioned in the data specification concept
  - Measures and VSL language: revised as needed for consistency with requirement language changes
- **Proposed IRO-014-3**:
  - Requirement R1: added 'implemented' so that an entity must both 'have' and 'implement' the plan
  - Requirement R1, Part 1.1: Revised to better align with the other parts of the Requirement
  - Requirement R1, Part 1.5: deleted as duplicative with proposed IRO-001-4 Requirement R1
  - Requirement R1, Part 1.6: Revised to better align with the other Parts of the requirement and changed 'weekly conference calls' to 'periodic communications to

support reliable operations' so that communications will occur as needed and to allow for other forms of communication
    - Requirement R3: deleted as duplicative of proposed IRO-014-3 Requirement R1 Part 1.1
    - Requirement R4: deleted as duplicative with proposed IRO-014-3 Requirement R1, Part 1.5
    - Requirement R5 (now R3): added 'expected or actual' to Emergency to clarify the intent of the requirement and also added 'in its Reliability Coordinator Area' to bound the requirement
    - Requirement R6 (now R4): replaced 'problem' with 'Emergency' for consistency
    - Requirement R7 (now R5): added 'in its Reliability Coordinator Area' to bound the requirement and also added 'impacted' to clarify the obligation
    - Requirement R9 (now R7): changed 'entity' to 'Reliability Coordinator' for clarity
    - Requirement R2 VSL: shifted the Low and Moderate VSLs for consistency with approved practices
    - Measures and VSL language: changed language as needed for consistency with requirement language changes
- **Proposed IRO-017-1**:
    - Purpose: added the time frames in which coordination of outages is intended to take place
    - Requirement R1, Part 1.1.2: deleted 'prior to submitting to Reliability Coordinators' as each Reliability Coordinator is able to define the process to best fit its area
    - Requirement R1, Part 1.1.3: changed 'Reliability Coordinator Wide Area' to 'Wide Area' for consistency
    - Requirement R1, Part 1.1.5: deleted as redundant and unnecessary
    - Requirement R1 VRF: changed from 'Low' to 'Medium' to be consistent with proposed IRO-005-3.1a Requirement R6
    - Requirement R2: changed 'follow' to 'perform the function specified in' for clarity
    - Requirement R2 VRF: changed from 'Low' to 'Medium' to be consistent with proposed IRO-017-1 Requirement R1
    - Requirement R4: re-worded to emphasize the joint development aspects of the requirement and to provide a bound on the timeframe
    - Requirement R1 VSL: changed to incremental approach for consistency with proposed IRO-005-3.1a Requirement R6
    - Measures and VSL language: changed language as needed for consistency with requirement language changes
- **Proposed TOP-001-3**:
    - Definitions: added 'applicable' to modify 'inputs' to indicate that an entity can only use as inputs that data which it actually has and changed 'contracted' to 'third-party'- for clarity

- Requirement R1: deleted first instance of 'Transmission Operator Area' to address comments on entities and deleted 'functions' for clarity as the issue is reliability and not undefined functions
- Requirement R2: changed for consistency with requirement R1 language
- Requirement R4: deleted 'citing one of the specific reasons shown in Requirement R3' as it is redundant
- Measure M4: corrected entity name to 'Generator Operator'
- Measure M5: corrected entity from 'Transmission Operator' to 'Balancing Authority'
- Measure M6: corrected entity from 'Balancing Authority' to 'Transmission Operator'
- Requirement R7: deleted 'Balancing Authority' as it can't respond to other Transmission operators – if it can assist it should receive instructions from its Transmission Operator; added 'other' to provide clarity as to who is being assisted; added 'and able as assistance can only be provided if the entity is able to provide it
- Requirement R8: added 'known' and 'known other' to modify 'impacted' to provide boundaries to focus the notification
- Requirement R9: deleted 'negatively' to clarify that any impacted entity should receive notification; deleted 'telecommunication' as it is duplicative of proposed COM-001—2 Requirement R10
- Measure M9: corrected the language to correspond with the language of requirement R9
- Requirement R10: re-arranged the language to provide clarity as to the intent of what is to be monitored; clarified that sub-100 kV facilities are as identified to avoid redundancy and provide clarification
- Requirement R13: Revised 'perform' to 'ensure' that the Real-time Assessment 'is performed' to acknowledge the situation where capabilities are unavailable and back-up methods are employed, and to allow for situations where arrangements exist for a third party to perform the real-time Assessment
- Requirement R16: added 'maintenance' and 'telecommunication' for consistency with proposed IRO-002-4 Requirement R3
- Requirement R17: made corresponding changes to match up with Requirement R16
- Requirement R18: deleted 'Generator Operator' as the Generator Operator will receive instructions as to the parameter to use; changed 'derived limits' to 'SOLs' to clarify the actual limits being discussed in the requirement
- Requirements R19 and R20: added for consistency with proposed IRO-002-4, Requirement R1
- Data retention: changed data retention for operator logs to 90 calendar days for consistency with voice recordings
- Requirement R8 VSL: added a gradated approach to account for differential impacts of the VSLs on smaller entities
- Measures and VSLs: Revised as needed for consistency with changes to requirements

- **Proposed TOP-002-4**:
  - Definition: added 'applicable' to modify 'inputs' to indicate that an entity can only use as inputs that data which it actually has and changed 'contracted' to third-party- for clarity
  - Requirements R3 and R5: deleted 'NERC registered' from entities so that entities identified in the plan are notified regardless of NERC registration
  - Data retention: changed data retention for operator logs to 90 calendar days for consistency with voice recordings
  - Measures and VSLs: Revised as needed for consistency with changes to requirements
- **Proposed TOP-003-3**:
  - Effective date: changed first step from 10 months to 9 months to better align with possible approval dates
  - Requirement R5: deleted 'Interchange Authority' as no data comes directly from that entity
  - Requirement R5 VSL: added increments for consistency with approved IRO-010-1a Requirement R1
  - Measures and VSLs: Revised as needed for consistency with changes to requirements
- **Implementation Plan for proposed IRO-010-2 and TOP-003-3**
  - Changed first step from 10 months to 9 months to better align with possible approval dates
  - Added language to account for different possibilities in the timing of regulatory approvals of this project and the petition that includes proposed COM-001-2 and the definition of Operating Instruction

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sandra Shaffer	PacifiCorp						X				
N/A													
2.	Group	Guy Zito	Norteast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co, of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company		1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
4.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
5.	Group	John A. Libertz	FRCC Operating Committee (Member Services)	X				X					

N/A

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	1, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	

				1	2	3	4	5	6	7	8	9	10
7.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
8.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gerald Beckerle	Ameren	SERC	1, 3
2.	William Berry	OMU	SERC	3
3.	Phil D'Antonio	PJM	SERC	2
4.	Dan Roethemeyer	Dynegy	SERC	5
5.	Joel Wise	TVA	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company;	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
10.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton	NERC Compliance Policy	NPCC	5
2.	Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Connie Lowe	NERC Compliance Policy	RFC	5, 6

				1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Mike Blough	Kissimmee Utility Services	FRCC	5
11.	Tom Reedy	Florida Municipal Power Pool	FRCC	6

				1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils			1
2.	Lee Schuster			3
3.	Dale Goodwine			5
4.	Greg Cecil			6

				1	2	3	4	5	6	7	8	9	10
13.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6
2. Rene Free	Santee Cooper	SERC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Erika Doot	Bureau of Reclamation	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. Rick Jackson	Bureau of Reclamation	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2. Pat G. Harrington	BC Hydro	WECC	3
3. Clement Ma	BC Hydro	WECC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. DeWayne Scott		SERC	1
2. Ian Grant		SERC	3
3. David Thompson		SERC	5
4. Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Cindy Stewart	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	William J Smith	FirstEnergy Corp	RFC	1
2.	Douglas G Hohlbaugh	Ohio Edison	RFC	4
3.	Kenneth J Dresner	FirstEnergy Solutions	RFC	5
4.	Kevin J Querry	FirstEnergy Solutions	RFC	6

				1	2	3	4	5	6	7	8	9	10
19.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Bensky	ITC Holdings	SPP	1
2.	Richard Bohnet	Omaha Public Power District	MRO	1, 3, 5
3.	Jamison Cawley	Nebraska Public Power District	MRO	1, 3, 5
4.	Michelle Corley	Cleco Power	SPP	1, 3, 5, 6
5.	Dave Dieterich	Omaha Public Power District	MRO	1, 3, 5
6.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
7.	Abubaker Elteriefi	ITC Holdings	SPP	1
8.	Neal Faltys	Omaha Public Power District	MRO	1, 3, 5
9.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
10.	Vinit Gupta	ITC Holdings	SPP	1
11.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
12.	Brett Holland	Kansas City Power & Light	SPP	1, 3, 5, 6
13.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
14.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
15.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
16.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
17.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
18.	Ron Losh	Southwest Power Pool	SPP	2
19.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
20.	Shannon Mickens	Southwest Power Pool	SPP	2
21.	Michael Moltane	ITC Holdings	SPP	1
22.	Jim Nail	City of Independence, MO	SPP	3
23.	Si Nguyen	Omaha Public Power District	MRO	1, 3, 5
24.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
25.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

26.	Johnna Sargent	Omaha Public Power District	MRO	1, 3, 5
27.	Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
28.	John Shipman	Omaha Public Power District	MRO	1, 3, 5
29.	Sing Tay	Oklahoma Gas and Electric	SPP	1, 3, 5
30.	Josh Verzal	Omaha Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
20.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ginger Mercier	Prairie Power, Inc.	SERC	3
2.	Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4
3.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
9.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
10.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

				1	2	3	4	5	6	7	8	9	10
21.	Group	Greg Campoli	ISO/RTO Standards Review Committee (SRC)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mathew Goldberg	ISO-NE	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Cheryl Moseley	ERCOT	ERCOT	2
4.	Charles Yeung	SPP	SPP	2
5.	Terry Bilke	MISO	MRO	2
6.	Ali Miremadi	CAISO	WECC	2

				1	2	3	4	5	6	7	8	9	10
22.	Group	Jared Shakespeare	Peak Reliability	X									

N/A

				1	2	3	4	5	6	7	8	9	10
23.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
	1. John Anasis	Technical Operations	WECC 1										
	2. Steve Hitchens	Technical Operations	WECC 1										
	3. Tanner Brier	Generation Scheduling	WECC 5										
	4. Stacen Tyskiewicz	Energy Management Systems	1										
	5. Steve Kerns	Short Term Planning	6										
24.	Individual	Scott McGough	Georgia System Operations			X	X						
25.	Individual	Greg Froehling	Rayburn Country Electric Cooperative			X							
26.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC.	X		X							
27.	Individual	Tom Haire	Rutherford EMC			X							
28.	Individual	Heather Bowden	EDP Renewables North America LLC					X					
29.	Individual	Terry Volkmann	Volkmann Consulting								X		
30.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
31.	Individual	Chris scanlon	Exelon Ccompanies	X		X		X	X				
32.	Individual	Ronnie Hoeinghaus	City of Garland	X		X		X					
33.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
34.	Individual	Glenn Pressler	CPS Energy	X		X		X					
35.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
36.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
37.	Individual	Anthony Jablonski	ReliabilityFirst										X
38.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
39.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
40.	Individual	David Austin	NIPSCO	X		X		X	X				
41.	Individual	Dave Willis	Idaho Power	X									
42.	Individual	Laurie Williams	PNMR	X		X							
43.	Individual	David Kiguel	n/a								X		
44.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
45.	Individual	Catherine Wesley	PJM Interconnection		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Thomas Standifur	Austin Energy	X		X		X		X			
47.	Individual	David Jendras	Ameren	X		X		X	X				
48.	Individual	Charles Rogers	Consumers Energy			X	X	X					
49.	Individual	Daniel Duff	Liberty Electric Power, LLC					X					
50.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
51.	Individual	Scott Langston	City of Tallahassee	X									
52.	Individual	Bill Fowler	City of Tallahassee			X							
53.	Individual	Josh Smith	Oncor Electric Delivery LLC	X									
54.	Individual	Michael Moltane	ITC	X									
55.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
56.	Individual	Ayesha Sabouba	Hydro One	X		X							
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Leonard Kula	Independent Electricity System Operator		X								
59.	Individual	Ayesha Sabouba	Hydro One	X		X							
60.	Individual	James Nail	INDN - Independence Power & Light					X					
61.	Individual	NIck Braden	Modesto Irrigation District			X	X	X					
62.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
63.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
64.	Individual	Joe Tarantino	Sacramento Municipal Utility District/Balancing Authority Northern California	X		X	X		X				
65.	Individual	Gordon Dobson-Mack	Powerex Corp.						X				
66.	Individual	Richard Vine	California ISO		X								
67.	Individual	Karin Schweitzer	Texas Reliability Entity										X
68.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
69.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	Rich Salgo	NV Energy	X		X		X					
71.	Individual	Terry Harbour	MidAmerican Energy	X		X							

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT has considered your support of the indicated comments in its deliberations.

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	We agree with the comments submitted by SERC OC Group.
Tennessee Valley Authority	Agree	SERC OC Review Group
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
Kansas City Power and Light	Agree	SPP - Robert Rhodes
City of Tallahassee	Agree	The FRCC Operating Committee (Member Services)
Omaha Public Power District	Agree	SPP RTO Comments submitted by Robert Rhodes.
Powerex Corp.	Agree	BC Hydro's comments submitted by Patricia Robertson.
ITC		SPP Standards Group
Lincoln Electric System		MRO NSRF
Response: Thank you for your response.		

1. **Do you agree with the changes made to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration:

The SDT has made the following changes due to industry comments:

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). An Operating Instruction applies to both Normal and Emergency operations. Therefore, the VSL should be graduated similar to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is a Moderate VSL.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. For VSL comment, see response to question 14.		
FRCC Operating Committee (Member Services)	No	R1 - Requirement R1 is not needed. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, we recommend removal of the Operations Planning horizon to narrow the focus of intent. As defined, the term Operating Instruction applies only to

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc. Florida Municipal Power Agency		"Real-time operation of the interconnected BES." In addition, the term Operating Instruction is too broad in scope because it applies to any "change in state, status, output, or input of an Element of the BES." The amount of documentation required for evidence would be very burdensome. R2 - TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. R3 - TSPs are not listed in the Functional Model for corrective actions issued by the RC. TSPs do not take actions to alter the state of the BES. We recommend to remove TSPs from this requirement. See comments supplied to R1 above. In addition, a correction is needed to refer to R1, instead of R2, when referencing the Operating Instruction issued by its RC.
Response: R1. The SDT believes Requirement R1 is needed and is responsive to concerns raised by FERC in the NOPR. The Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board and the SDT uses Board approved standards and definitions. No change made. R2. The SDT agrees and has deleted Transmission Service Provider from the requirement. See summary consideration for revision. R3. The SDT agrees and has deleted Transmission Service Provider from the requirement. With the corresponding deletion of Transmission Service Provider in Requirement R2, the Transmission Service Provider no longer appears as an applicable entity in any of the requirements and has also been deleted from the Applicability Section. See summary consideration for revision. The SDT corrected the error in Requirement R3 to refer to Requirement R1 instead of Requirement R2.		

Organization	Yes or No	Question 1 Comment
MRO NERC Standards Review Forum	No	R3 is predicated on R2 and only allows entities the inability to perform the issued Operating Instruction based on "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements". The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting "citing one of the specific reasons shown in Requirement R3", as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction.
Response: The SDT agrees that there are limited possibilities for not performing a Reliability Coordinator's Operating Instruction and therefore believes it is important to provide the specific criteria for not doing so. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in Requirement R2.		
Duke Energy	No	Duke Energy is concerned that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the RC "act" to ensure the reliability of its RC area is not only a requirement that the RC do its job for which other requirements are applicable, but also a requirement that could be interpreted to require the RC "act" to cover the full scope of any related RC reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirement should focus strictly on the communication desired when needed to ensure the reliability of the RC area. The definition of Operating Instruction makes these requirements (and standard as a whole), too broad in nature. The definition of Operating

Organization	Yes or No	Question 1 Comment
		Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R1: Duke Energy suggests re-writing R1 as follows: ”Each Reliability Coordinator shall issue Reliability Directives, as necessary, to ensure the reliability of its Reliability Coordinator Area.” As written, the language requires the RC to act to ensure the reliability if its area, which is similar to writing a requirement that the RC comply with all other RC requirements. The suggested language addresses that point and would eliminate the ambiguity that currently exists in the proposal that an RC must issue an Operating Instruction for all communications, and not when actually warranted. As written, this requirement could be interpreted to suggest that an RC would be non-compliant if at any time they did not issue an Operating Instruction notwithstanding system conditions. In any communication, the RC has the authority to issue a Reliability Directive whenever the circumstances warrant such authority. Also, we would like to add that the RC’s responsibilities outlined in R1 are inherent to the NERC Functional Model. Ultimately, we question the necessity of the proposed R1. R2: Duke Energy questions the addition of the TSP into the proposed R2. This requirement references compliance by an applicable entity to an RC’s Operating Instruction. An Operating Instruction is considered to be an action that takes place during Real-time operations. Per the NERC Functional Model, the relationship between the RC and the TSP is considered “Ahead of Time” in nature. Additionally, the Functional Model does not provide that an RC may actually direct a TSP to act, only that an RC may coordinate with a TSP on transmission system limitations. As with our

Organization	Yes or No	Question 1 Comment
		prior comment, we believe this requirement should be applicable those receiving Reliability Directives. R3: See our comment above regarding the relationship between the RC and the TSP above. Also, there appears to be an improper reference to R2 in this requirement. We believe the SDT meant to reference R1 instead, due to the actual issuance of an Operating Instruction from the RC takes place in R1, and not R2.
Response: R1 - The SDT believes Requirement R1 is needed and is responsive to concerns raised by FERC in the NOPR. The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made. For VSL comment, see response to question 14. R2 – The SDT agrees and has deleted Transmission Service Provider from the requirement. However, the Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. See summary consideration for revision. R3 – The SDT agrees and has deleted Transmission Service Provider from the requirement. See summary consideration for revisions. The SDT corrected the error in Requirement R3 to refer to Requirement R1 instead of Requirement R2. See summary consideration for revisions.		
Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Reliability Coordinators and Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g.

Organization	Yes or No	Question 1 Comment
		water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Reliability Coordinator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.
BC Hydro and Power Authority	No	The new Requirement has the Reliability Coordinator issuing "Operating Instructions" rather than "Reliability Directives". The scope of "Operating Instructions" broadens to non-emergency situations. BC Hydro does not support this increase in scope.
Consumers Energy	No	I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context.
Response: The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made.		
SPP Standards Review Group	No	Since there is no red-line for IRO-001-4, delete the last sentence in the Rationale Box for the Applicability Section.
Response: The SDT agrees and the last sentence in the rationale box in the Applicability section has been removed.		
ACES Standards Collaborators	No	(1) We agree with the removal of the PSE and LSE from IRO-001-4. It would be highly unusual for an RC to issue a directive to a PSE or LSE. (2) The use of "operating instruction" as a FERC-approved defined glossary term is problematic because FERC has not approved COM-002-4. We recommend including the proposed definition of Operating Instruction, as

Organization	Yes or No	Question 1 Comment
		stated in COM-002-4, in the Rationale Box above R1 that discusses the change from Reliability Directive to Operating Instruction. (3) We support the consolidation of IRO-004-2 by inserting the Transmission Service Provider into R2 and R3. We encourage the drafting team to further look for opportunities to reduce requirements and redundancy in the IRO and TOP standards. (4) For Requirement R2, we question the phrase "cannot be physically implemented" and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (5) For Requirement R3, we believe this requirement should be removed in its entirety. It meets Paragraph 81 criteria as an administrative documentation requirement. R2 clearly states that the applicable functions must comply unless there is a violation of other factors. The burden in R2 is on the entity to comply or to prove why they cannot comply. Therefore R3 is not needed. (6) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) Thank you for your support. (2) The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board and the SDT uses Board approved standards and definitions. No change made. (3) Thank you for your support. (4) The phrase "cannot be physically implemented" is intended for scenarios where, for example, a line or transformer is requested to be returned to service to resolve an issue, but the conductor is not in the air or the transformer has had its oil drained for maintenance, for example. No change made.		

Organization	Yes or No	Question 1 Comment
(5) The SDT disagrees that Requirement R3 is not needed. Requirement R3 requires communication to the Reliability Coordinator when an Operating Instruction cannot be performed. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in requirement R2. (6) For VSL comment, see response to question 14.		
Rayburn Country Electric Cooperative	No	I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3.Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is “Interconnection Reliability Operations and Coordination” and the purpose statement for TOP-001-3 is “To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: o Reliability Coordinator, o Balancing Authority, o Transmission Operator Receiving Entity Any one of the following functions: o Balancing Authority, o Transmission Operator, o Transmission Service Provider, o Generator Operator, o Load Serving Entity o Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity

Organization	Yes or No	Question 1 Comment
		in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Response: The SDT appreciates your creative approach to consolidating and simplifying requirements but believes all of the requirements are necessary and must be separate to reflect the operational hierarchical structure. For instance, Requirement R3 does not apply to a Transmission Operator because a Transmission Operator cannot issue operating instructions to another Transmission Operator. Requirement R5 is similar in that a Balancing Authority cannot issue Operating Instructions to other Balancing Authorities. However, a Reliability Coordinator can issue Operating Instructions to both. Combining the requirements and respecting this operational hierarchy would make the requirements quite cumbersome. In addition, this project inherited the scope of Projects 2006-06 and 2007-03 which indicated industry preferences for keeping the functions separate. No change made.		
City of Garland	No	Requirement 1Concern # 1The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action - therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1Replace this proposed requirement with the existing requirements concerning authority. Concern # 2The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at

Organization	Yes or No	Question 1 Comment
		the time. Recommendation # 2Replace this proposed requirement with the existing requirements concerning authority.
Austin Energy	No	City of Austin dba Austin Energy (AE) does not agree with the change to R1, which removes the "clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE offers more comments on this matter with regards to TOP-001-3 below.
Response: The SDT intentionally removed the existing requirements concerning authority because it does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. The IERP Report also points to actions versus authority which is performance-based. No change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP ("ICLP") believes the changes made to IRO-001-4 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions - not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of IRO-001-4. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business - by far the larger category - must be excluded. IRO-001-4 R1 has simply removed the limitation that the applicable Operating

Organization	Yes or No	Question 1 Comment
		Instructions are those made during an Emergency or Adverse Reliability Impact. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirement R1 specifically limiting its applicability to a set of defined circumstances. A better method may be to require the RC to identify the Operating Instruction as "critical" to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP does not agree with the removal of the qualifier in R3 that the Operating Instruction recipient must notify the issuer "upon recognition" of its ability to perform it. This language was added to account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith - but finds out later they cannot. As such, the qualifier should be reinstated.
Response: The SDT believes the use of Operating Instruction is responsive to concerns raised by FERC in the NOPR. The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency by issuing specific command(s) for action to be taken. As stated in the definition, discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command, which the SDT believes addresses the concern of administrative burden. The "upon recognition" wording was not removed as it is not in the currently enforceable version of this standard. The SDT feels Requirements R2 and R3 as currently worded correctly address a situation where an entity initially feels an Operating Instruction can be executed, but later realizes it cannot. Once the entity realizes the Operating Instruction cannot be executed, it must notify the Reliability Coordinator. No change made.		
Idaho Power	No	N/A
MidAmerican Energy	No	

Organization	Yes or No	Question 1 Comment
Response: Without specific comments, the SDT is unable to respond.		
Liberty Electric Power, LLC	No	There is no requirement for the RC to identify the Operating Instruction as such. In some areas the same individual could be issuing a Directive, an Operating Instruction, or a market-related instruction. Unless the requestor identifies the status of the request, the receiver will have no idea if he is required to comply.
Response: The SDT believes the definition of Operating Instruction adequately identifies the conditions for issuing the Operating Instruction. Proposed COM-002-4 lays out the requirements for three-part communication involving Operating Instructions. No change made.		
Electric Reliability Council of Texas, Inc.	No	The retirement of IRO-004-2 is predicated on the concept that an Operating Instruction applies outside of the real-time time horizon. Operating Instruction as defined is for real-time and not for the Operations Planning time horizon. As such, it does not cover the purpose and timeframe identified in IRO-004-2. Directing others to act outside of real time does not make sense as deciding to take actions in a future time is a plan, not a real-time instruction. Additionally Operating Instructions have no COM-002-4 requirements associated with a Transmission Service Provider. In summary, while the use of the term Operating Instruction provides some uniformity, it simply does not work in its current form for the Operations Planning timeframe. Some instructions outside of the real-time time horizon are carried out by systems or on non-recorded lines and perhaps even by operations support personnel. The definition when created by the OPCP SDT was for COM-002-4 and was not for the construct of current proposed IRO-001-4 draft. Any modifications to the definition could create issues for the COM-002-4 standard as well. ERCOT recommends removal of the operations planning time horizon and address needs separately for expectations related to that time horizon for issuing instructions as

Organization	Yes or No	Question 1 Comment
		necessary to plan for reliable operations. As an alternative, the definition could be modified and COM-002-4 modified to include "Real Time" in front of every instance of usage for "Operating Instruction" effectively moving real time out of the definition and making it an individual qualifier for each requirement as needed. For IRO-001 R1, ERCOT believes the existing requirement does not provide overlap as it ensures that entities have policies or controls providing such authority. The body of all other requirements provides the basis of the actual implementation of such authority through actions or directing to act. The current requirement appears now to be redundant with every other requirement that requires action from an RC. The evolution of this requirement has lost the "clear decision-making authority" portion which while not action-oriented provides a basis for System Operator judgment and authority. Having requirements worded this way can be a blanket requirement utilized by auditors to second guess an operator's perceived actions or inactions as a violation, while not regarding the clear decision-making authority a System Operator exercises with information available at a specific point in time. Additionally, when the current version IRO-001-1.1 loses the "within 30 minutes" language, it loses the original construct of this being a real time requirement and not something applied to same day or operations planning timeframe. It loses its purpose when trying to simply consolidate IRO-004 language with it. ERCOT recommends maintaining existing R1 language as much as possible as follows: "Each Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Reliability Coordinator Area. These actions shall be taken without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve

Organization	Yes or No	Question 1 Comment
		the original purpose of the requirement, address NOPR paragraph 64, and provide a timeliness requirement where appropriate for all requirements that require action by an RC in real time without redundancy. Additionally, recommend changing R1 to be actionable to current proposed language is inconsistently applied (e.g. TOP-001-3 R16, R17).
Response: The SDT believes the Operations Planning Time Horizon is required to include Operating Instructions issued by a Reliability Coordinator based on conditions seen in studies, from day-ahead up to and including seasonal, that may impact the Real-time reliability of the Reliability Coordinator Area. The SDT sees the definition as being 'timeless'. It does not state that an Operating Instruction is only issued in Real-time. It says that they can only be issued by those responsible for Real-time operations which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority by definition. No change made. However, the SDT has removed Transmission Service Provider from Requirements R2 and R3. See summary consideration for revision. The SDT intentionally removed the existing requirements concerning authority because it does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. The IERP Report also points to actions versus authority which is performance-based. No change made. The SDT believes that the language is consistently applied. No change made.		
Texas Reliability Entity	No	There appears to be a gap between IRO-001-4 and IRO-002-4 related to Operating Instructions. In COM-002-4, Operating Instructions are issued either as an oral two-party communication, multi-party burst communication, or written. IRO-002-4, R1, requires the RC to have voice communication facilities with TOPs, BAs and GOPs. IRO-002-4, R2, requires the RC to have data links with BAs, PCs, TPs, GOs, LSEs, TOPs, TOs and DPs. IRO-001-4 R2 states that TOPs, BAs, GOPs, TSPs, and DPs shall comply with RC Operating Instructions. The possible gaps lies in the fact the TSPs and DPs are not required to have voice communication facilities with the RC per IRO-002-4, which implies that the only method for communication of

Organization	Yes or No	Question 1 Comment
		Operating Instructions with TSPs and DPs would be in a written form. Please clarify if that was the intent of the SDT? In addition, TSPs are not required to have data links with the RC. With no required voice or data links what is the expectation for TSPs to receive Operating Instructions from the RC?
Response: The SDT has revised proposed IRO-002-4, Requirements R1 and R2. This should address your concerns. Please see responses to question 2. The SDT agrees and has removed Transmission Service Provider from Requirements R2 and R3. See summary consideration for revision.		
Georgia Transmission Corporation	No	(1) GTC does not believe that the DP should be an applicable entity to this standard. The RC would not direct a DP to perform Operating Instructions due to the proper chain of command. The RC would first direct the TOP. See RC section in the NERC Functional Model under System restoration actions "The Reliability Coordinator directs and coordinates system restoration with Transmission Operators and Balancing Authorities." Due to this proper chain of command, there is no reliability gap between the RC and the DP. The TOP, could further direct Operating Instructions during an Emergency to the DP per TOP-001-3. If the SDT does not remove the DP from applicability to this standard, then GTC recommends the following: (2) The current proposal for R2 as written could overly expose the DP to excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment "affecting the reliability of the BES" is not very routine. GTC believes the intent of this requirement for the DP should complement COM-002-4 R6 relating to

Organization	Yes or No	Question 1 Comment
		Operating Instructions during an Emergency "affecting the reliability of the BES". The use of the NERC term "Emergency" would capture this intent. GTC proposes the language "[during an Emergency]" be added after "....shall comply with its Reliability Coordinator(s) Operating Instructions [ ] ".
Response: (1) The SDT has revised proposed IRO-002-4, Requirements R1 and R2. This should address your concerns. Please see responses to question 2. (2) See response to the Distribution Provider concern in (1) above. With respect to the second part of the second comment, the SDT believes Operating Instructions should be issued in an Emergency or to address or prevent situations that could lead to an Emergency. If a Reliability Coordinator issues an Operating Instruction to ensure the reliability of its Reliability Coordinator Area, then that Operating Instruction must be followed unless one of the reasons in Requirement R2 apply. The SDT believes the requirements as written are responsive to concerns raised by FERC in the NOPR.		
ReliabilityFirst		ReliabilityFirst submits the following comments for consideration: 1. Requirement R3 - ReliabilityFirst recommends there be a timeframe be added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform the Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform Operating Instruction in a timely manner. ReliabilityFirst suggests the following for consideration. "Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator [within 30 minutes of receiving an Operating Instruction] of its inability to perform the Operating Instruction..."
Response: The SDT believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes they cannot implement the instructions for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT believes that Operating Plans and Operating Instructions may include a time line and that		

Organization	Yes or No	Question 1 Comment
a time line is not necessary, or appropriate, for a requirement. A generic time requirement in a requirement may actually prove to be detrimental to reliability. No change made.		
SERC OC Review Group	Yes	The SERC OC Review Group requests clarification on who “others” are for R1: “RC shall act, or direct others to act,” Suggestion: “directs others (as identified in R2) to act”. Current: “Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.” Suggested: “Each Reliability Coordinator shall act, or direct others (as identified in R2) to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.”
Response: The “others” referred to in Requirement R1 are those entities listed in Requirement R2. No change made.		
Hydro One	Yes	R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC-wide area review responsibility.
Response: There is no Requirement R10 in this standard. The SDT believes the reference should be for proposed TOP-001-3 and points the commenter to question 7.		
Salt River Project	Yes	R3 requires an entity to cite one of the reasons in R2 for an inability to perform an Operating Instruction. SRP expresses concern over only permitting a predetermined list of rational for not performing an Operating Instruction. Situations may arise that do not fit nicely into one of the given reasons. IT is suggested to allow for other rational for not performing Operating Instructions.
Response: The SDT believes Requirement R2 adequately provides the criteria for a situation where an Operating Instruction cannot be complied with. However, the SDT agrees it is not necessary or beneficial to reliability to cite the reasons at the time of the event. The specific reason(s) why an entity was unable to perform an Operating Instruction would be discussed after the issue requiring action was resolved. The reason(s) would still need to be in accordance with those specified in Requirement R2. No change made.		

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
Colorado Springs Utilities	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
FirstEnergy	Yes	
ISO/RTO Standards Review Committee (SRC)	Yes	

Organization	Yes or No	Question 1 Comment
Peak Reliability	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
Rutherford EMC	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Ccompanies	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	R1 - N/AR2 and R3 - ATC agrees with the proposed IRO-001-4 Requirements R2 and R3.
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
NV Energy	Yes	
Response: Thank you for your response.		

2. **Do you agree with the changes made to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has provided clarification to numerous concerns and made the following changes due to industry comments:

R1.

R2. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R4. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention (page 7). Requirements R1 and R2 appear redundant to the COM-001 Standard; suggest these requirements be deleted. R1 requires voice communication as opposed to the COM-001-2 requirement for the RC to utilize Interpersonal Communication, which is defined as "Any medium that allows two or more individuals to interact, consult, or exchange information." Is a RC supposed to have voice communication and

Organization	Yes or No	Question 2 Comment
		Interpersonal Communication, or does voice communication apply to both IRO-002 and COM-001? If this is the case, then these two requirements are redundant. R2 requires data links while the VSL utilizes data link facilities. We prefer the use of data link facilities. The use of facilities would imply that this is not a SCADA point by point requirement but an overall emplacement of equipment required to transmit data. It also helps address the concern that the requirement as written implies the data link is operational 24/7. The NERC Event Analysis Program has issued lessons learned where data communications between entities have been interrupted due to EMS issues. Finally, it would avoid any redundancy with the proposed IRO-010 R3 or IRO-014 R3. R3- System Operators should have authority to both approve and disapprove planned outages. From R3, "...maintenance of its monitoring and analysis capabilities." What is "its" referring to? The Rationale isn't clear on this either. R4- Suggest rephrasing R4 because the last phrase starting with word "including" is modifying the Facilities being monitored and not the type of exceedances being monitored for. Reword to "Each Reliability Coordinator shall monitor facilities, including sub-100 kV facilities when necessary and the status of Special Protection Systems in its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." R5 contains some 'how, not why' language: "giving particular emphasis to alarm management and awareness systems, automated data transfers," which may, in fact, produce a lowest common denominator approach to EMS systems. A part of the Requirement is also redundant to COM-001: "over a redundant and highly reliable infrastructure." R5 could be improved to become performance oriented by removing ambiguous terms. For example, what is the measure of particular emphasis, and highly reliable? Also, does redundancy mean to have a Primary and Backup in which

Organization	Yes or No	Question 2 Comment
		case EOP-008 already requires this redundancy? We suggest rephrasing to: Each Reliability Coordinator shall have systems that provide Real-time situational awareness of the BES to its System Operators.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. The SDT agrees and has made the suggested changes. See summary consideration for revisions. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT does not agree that Requirement R2 is redundant with proposed COM-001-2 as that standard is about 'persons' communicating and not data. No change made. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. "its" is used to imply ownership. In other words, the responsible entity is responsible only for its own "monitoring and analysis" capabilities. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
FRCC Operating Committee (Member Services)	No	We recommend the removal of the Operations Planning horizon from this Standard. The Purpose of this Standard states "Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions." This would not apply in the Operations Planning horizon.

Organization	Yes or No	Question 2 Comment
Seminole Electric Cooperative, Inc. Florida Municipal Power Agency		R1 - This requirement is duplicative with currently enforced COM-001-1.1 R1 and future COM-001-2 R1. The communication with GOPs should be done through BA because the BA/TOP should be aware of actions being taken in regards to generation. The term “voice communications” should be singular. R2 - The term “data links” lends to the idea of an electronic submittal. PCs, TOs, GOs, LSE, DPs and TPs do not need to provide real time data. We recommend the language be modified to allow for data links with BAs and TOPs. The requirement could also state that TOs, GOs, GOPs, LSEs, and DPs shall provide, or have provisions for, the data via their host BA/TOP. We recommend PCs and TPs be removed from this requirement. R3 - The language “to approve” does not seem to cover the full spectrum of authority needed by the RC. We recommend the following language: ”Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.” R4 - To eliminate confusion, we recommend creating two requirements with the following language: Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R5 - This requirement does not seem to be measurable. What does “over a redundant and highly reliable infrastructure” mean? What is an acceptable level of synchronism and reliability? How are these terms going to be measured?

Organization	Yes or No	Question 2 Comment
		We recommend adding an additional requirement stating: "Each RC shall monitor identified phase angle limitations within its RC Area." This will eliminate the need for the phase angle language within the new Real-time Assessment term definition.
Response: The SDT believes the Time Horizons are appropriately used. Requirements R1, R2, and R3 deal with information that could be used to run various studies including Real-time Assessments and Operational Planning Analyses as well as planned outages. These occur in the Operations Planning Time Horizon. No change made. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. The SDT does not believe a new requirement is needed to address 'identified' phase angle limitations as it is correctly handled by including it in the Real-time Assessment and Operational Planning Analysis definitions. No change made.		
MRO NERC Standards Review Forum	No	R5. The NSRF does not agree with the ambiguous wording of "over a redundant" and "highly reliable infrastructure". EOP-008-1, R3 requires an RC to have a backup control center facility not dependent on the primary control center. This is the same type of required items within R5. Recommend deleting "over a redundant" in order to remove the similar language and remove the possibility of double jeopardy. Concerning the word of "highly reliable infrastructure", we do not believe that an RC would utilize "slightly reliable infrastructure". This ambiguous wording will be a compliance night mare as it will always be subjective in nature. Recommend deleting "highly reliable infrastructure". A simple recommendation would be to remove the

Organization	Yes or No	Question 2 Comment
		wording of "over a redundant and highly reliable infrastructure" and replace it with "over a system that is not impacted by a single point of failure".
Response: The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	The SERC OC Review Group has concerns adding TP, PC, and DP to real-time data requirements to R2. DP provides info to TOP who then provides info to RC. Neither the TP nor PC provides the RC real time data, thus not requiring a data connection.
Response: The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing Georgia System Operations Georgia Transmission Corporation	No	Although the SDT's Rationale indicates there is no redundancy with proposed requirements in this Project 2014-03, Southern believes Requirements 1 and 2 are redundant with existing effective COM-001-1 R1 and future mapping of this requirement to future enforceable standards. Southern also notes that COM-002-2 R1 is the corresponding requirement for the TOPs and BAs to have both voice and data links with appropriate RCs, BAs, and TOPs. Southern suggests that these existing standards and other industry approved future enforceable standards addresses any reliability gaps. Southern also suggests that R2 is redundant with both the existing and proposed IRO-010 in this project. IRO-010 already requires the RC to provide data specifications to the entities listed in R2 and requires such entities to provide the data specified by the RC. Southern recommends that both R1 and R2 be removed. As an alternative to removing R2, Southern suggests that TPs/PCs be removed from R2 because these functional entities were specifically added to IRO-010 for purposes of providing UFLS and UVLS data to RCs. They do not need to be in both standards. The proposed Requirement 3 needs to be revised to clarify that it is only addressing monitoring and analysis capabilities and not planned outages and maintenance of BES elements. As currently drafted, one could interpret it as planned outages of BES

Organization	Yes or No	Question 2 Comment
		element and maintenance of monitoring and analysis capabilities, and Southern does not think that is the intent of the SDT. Southern suggest changing the requirement to, "Each Reliability Coordinator shall provide its System Operators with the authority to approve the following: R3.1. Planned outages of its monitoring and analysis capabilities.R3.2. Maintenance of its monitoring and analysis capabilities. Requirement 4, as proposed, does not indicate how far into the neighboring system a RC should monitor. Southern suggest incorporating language referencing the RCs wide area view methodology and language specifying that it should include sub-100 kV facilities, "as deemed necessary by the RC" (similar to the language used in the proposed IRO-010-2 R1.1). Southern proposes the following verbiage to add clarity to the requirement: "Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas consistent with its wide-area view methodology to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area , including sub-100 kV facilities, as deemed necessary by the Reliability Coordinator, and the status of Special Protection Systems, to make this determination."
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that proposed IRO-002-4 deals with data link facilities proposed while IRO-010-2 spells out what specific data is needed. Therefore the SDT does not believe there is any redundancy. No change made. The SDT believes the language is clear as written and that the suggested change does not add clarity. No change made. The SDT believes that the requirement as written provides for each Reliability Coordinator to use its professional and technical judgment to determine what it needs to monitor and that this is the correct path to take for system reliability. However, the SDT has changed the wording of the requirement in response to other comments. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
Dominion	No	Dominion does not agree with requirement 1 as it is very similar to COM-001-2, R1 and because we do not agree that the Reliability Coordinator should be required to have direct communications facilities with Generator Operators within its Reliability Coordinator Area. We believe that the Interpersonal Communication capability developed pursuant to COM-001-2 could allow the Reliability Coordinator to communicate to Balancing Authorities or Transmission Operators in its Reliability Area, and requiring that entity to communicate directly with other operators and users (including DP, GOP and LSE). Dominion does not agree with requirement 2 as written. While we agree that each Reliability Coordinator should have data links with each Balancing Authority and Transmission Operator within its reliability area and with neighboring Reliability Coordinators, we do not agree that it should be required to have data links with all Generator Owners, Generator Operators, Load-Serving Entities Transmission Owners, and Distribution Providers in its reliability area. We believe this requirement should NOT apply if the Reliability Coordinator's documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments (pursuant to Proposed IRO-010-2, Requirements R1 and R3, part 3.3) allows for the data to be provided via data links with a Balancing Authority or Transmission Operator within its reliability area. We can agree that data links with Planning Coordinators or Transmission Planners be required only if the Reliability Coordinator identifies the need for data pursuant to IRO-010-2. Dominion does not see the need for Requirement 3. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We would prefer to modify the requirement

Organization	Yes or No	Question 2 Comment
		to read "Each Reliability Coordinator shall monitor BES Facilities, and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. 2nd citing of R4 in the mapping document Dominion does not agree with R4 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We would prefer to modify the requirement to read "Each Reliability Coordinator shall monitor BES Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area and the status of Special Protection Systems in its Reliability Coordinator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT does not believe approval of planned outages and maintenance of its own monitoring and analysis capabilities falls under the realm of acting or directing others to act as this authority more governs issuing Operating Instructions to other entities. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The mapping document has been updated accordingly.		
Duke Energy	No	R1: (1) Duke Energy believes that this requirement is duplicative with the currently enforced COM-001-1.1 and the future COM-001-2 and suggest removing this

Organization	Yes or No	Question 2 Comment
		requirement or clarify the need to have this requirement in conjunction with the COM-001 requirements. (2) Per the Functional Model, the RC directly communicates with the BA and TOP only and should have voice communications facilities with those Functional Entities. Communications to the GOP would come from either the TOP or BA. R2: The RC should only be required to have data links with the TOPs and BAs only. Data links from the GO, TO, GOP, LSE and DP would come from their host TOP or BA. The RC could have a process or provision in place to receive the data from those entities via the host TOP or BA in their RC area. Again, this is out of scope with the Function Model. R3: - Duke Energy suggests the following language: "Each RC shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools." The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the RC should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the RC needs to have the authority to deny that request. R4: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: "Each Reliability Coordinator shall monitor Facilities, and identified sub-100 kV facilities, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability

Organization	Yes or No	Question 2 Comment
		Coordinator Areas necessary to determine any potential SOL and IROL exceedances within its Reliability Coordinator Area." We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by an RC. R5: Duke Energy has concerns that this requirement, as written, is not measurable. We seek clarity on the phrase "over a redundant and highly reliable infrastructure". It is not clear to us what is considered an acceptable level of synchronism and reliability, and therefore have concerns how this will be measured. We suggest rewording this requirement for clarity or removing from this standard.
Response: (1) The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. (2) The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. R3. The SDT placed the authority on the System Operator since they are the ones using and monitoring the real time tools and the ones who need to have the control, not the entity. This should not place a burden on the System Operator. The Operations Planning Time Horizon is captured for planned maintenance and outages. The SDT believes that by having the authority to approve the System Operator can also implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
Bureau of Reclamation	No	Reclamation believes that, like under IRO-002-2, Reliability Coordinators should be able to have data links with Transmission Operators and Balancing Authorities, who in turn communicate with Generator Operators and Distribution Providers. Reclamation believes that Reliability Coordinators should be able to elect this model so that Transmission Operators and Balancing Authorities are aware of all instructions regarding generation and transmission that are issued in their control areas.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
SPP Standards Review Group	No	Requirement R1 is redundant in that Requirement R1 of COM-001-2 already requires the Reliability Coordinator to have Interpersonal Communication capabilities. Therefore, this requirement should be eliminated for Paragraph 81 considerations. Requirement R2 requires the Reliability Coordinator to have data links with several non-traditional functional entities that are not normally associated with the exchange of Real-time data. Data links have specific connotations associated with specific equipment such as ICCP, etc. We would suggest that the language in this requirement be revised to parallel the language in IRO-010-2, Requirement R2. This also parallels the language in the COM standards. We would go on to suggest that since the requirement for the data to be supplied is contained in IRO-010-2, this specific requirement is redundant and too prescriptive in that it addresses how the exchange of data is to be accomplished rather than the real objective of exchanging data which is addressed in IRO-010-2. Requirement R5 requires a 'redundant and highly reliable infrastructure' for the exchange of data. This appears to be redundant with EOP-008-1, Requirement R6 which already calls for backup control centers which are not dependent upon the primary site for functionality. Since redundancy is already required by EOP-008, there is no need for Requirement R5.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
The SDT believes that proposed IRO-002-4 deals with data link facilities proposed while IRO-010-2 spells out what specific data is needed. Therefore the SDT does not believe there is any redundancy. No change made. The SDT has deleted the term ‘and highly reliable’ as it is unmeasurable. See summary consideration for revision.		
ACES Standards Collaborators	No	(1) The list of entities that the RC should have data links with should be reduced to include only operational entities. Inclusion of Planning Coordinators does not make sense because they have no real-time data to provide. We question inclusion of equipment owners such as TOs and GOs since the associated operational entities are already included. The associated operational entities should be able to provide any data that the equipment owner can provide. (2) Requirement R4 is problematic as written because it implies that sub-100 kV transmission equipment are Facilities (i.e. the NERC defined term). They may be if they are part of the BES Otherwise, they are not. A simple solution would be to remove the clause “including sub-100 kV facilities needed to make this determination”. If these sub-100 kV facilities are needed they should probably be part of the BES and will be covered by the NERC defined term “Facilities” making the clause superfluous. (3) For Requirement R5, we recommend removing the phrase “highly reliable.” This is subjective, vague, and does not belong in a reliability standard. Redundancy should provide the requisite reliability for monitoring systems. If the drafting team believes that RCs should have tertiary redundancies or meet some service level, then state that as a requirement. (4) For Requirement R5, we also question the term “giving particular emphasis to alarm management” because it is ambiguous, vague, and not measurable. (5) We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		

Organization	Yes or No	Question 2 Comment
(2) The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. (3) The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. (4) While the SDT understands that the commenter may feel that the term is vague, the SDT believes that it places emphasis on the condition and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made. (5) See response to Q14.		
ISO/RTO Standards Review Committee (SRC)	No	R1 and R2 appear redundant to the COM-001 Standard; suggest deleting these. We agree that a better distinction is required between voice and data requirements. However it should be added to COM-001 or remove COM-001. R4: The "Rationale" for the new R4 as being responsive to the NOPR where the Commission indicates "the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator...." However, other functional entities are not "backed up" and EOP-008 now contains backup provisions for reliability: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost." R5 contains some 'how, not why' language: "giving particular emphasis to alarm management and awareness systems, automated data transfers," which may, in fact, produce a lowest common denominator approach to EMS systems and a part of the Requirement is also redundant to COM-001: "over a redundant and highly reliable infrastructure." R5 - Terms like "particular emphasis" and "Highly reliable" are not defined terms. They should be deleted or the requirement should include defined values for them for clarity.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision. While the SDT understands that the commenter may feel that the terms are vague, the SDT believes that it places the proper emphasis on the conditions and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made.		
Peak Reliability	No	R1: What is the definition of “voice communication facilities”? Is a list of phone numbers and a phone system sufficient? R2: “Data link” is not a defined term. “As required for reliable operations in the Interconnection” should be added to R1 and R2. RC data links with TPs, PCs, GOPs, LSEs, and DPs are not required for reliable operations. It is sufficient for the RC to have data links with BAs and TOPs, and get TP/PC/GOP/LSE/DP data from BAs and TOPs. R3: The word “approve” should be changed to “disapprove”. System Operators may not always have the understanding of the maintenance to actively “approve” it, but their authority should be to disapprove planned tool outages if they will adversely impact real-time operations or if System Operators need more time to assess a tool outage. R4: The way it is phrased gives risk for misunderstanding. Is the Requirement that RCs must “monitor” the status of RAS? Or is the Requirement that the RC must understand/model the impact of the RAS so that the RC knows the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The

Organization	Yes or No	Question 2 Comment
		way it reads it seems the RC is only required to "monitor" the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the RC needs to monitor facilities in adjacent RCs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase "as needed" to "and neighboring Reliability Coordinator Area" adds more clarity.
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. The SDT believes that the suggested change is unnecessary. The Reliability Coordinator should establish facilities with the entities listed as they are the ones required for reliable operations. No change made. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. R3. The SDT felt that by having the authority to approve the System Operator also could implicitly cancel or deny an outage as well. No change made. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
Ingleside Cogeneration LP	No	Requirement R4 calls for the Reliability Coordinator to monitor certain sub-100 kV facilities that to ensure operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied

Organization	Yes or No	Question 2 Comment
		unevenly across Reliability Coordinators; which works against the fundamental intent of reliability standardization.
Response: The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
NIPSCO	No	1. In R5 the term "highly" reliable is used. Please define "highly". 2. In R2 "data links" needs to be defined, as well as the context in which they are to be used (what are the data links for?). 3. Should R1 and R2 be contained in the COM standards, as opposed to IRO-002? 4. R3 should be included in IRO-017, as it is an outage coordination requirement.
Response: 1. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision. 2. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. 3. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. 4. Requirement R3 is only applicable to a Reliability Coordinator's System Operators having the authority to approve planned outages and maintenance of its own monitoring and analysis capabilities. It is not associated with interconnected transmission system outages which is the subject of proposed IRO-017-1. No change made.		
David Kiguel	No	R1: The requirement of voice communications facilities is a matter to be addressed by COM standards. Inclusion in IRO-002-4 could introduce compliance issues (double jeopardy). R4: Requires RC to monitor facilities in neighboring Reliability Coordinator Areas i.e. outside of its own.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. R4. The SDT agrees that the language in Requirement R4 could be clearer and has made changes to conform to your comment and those of others. The Rationale Box has been expanded to explain the changes. See summary consideration for revision.		
PJM Interconnection	No	Specific to R2, PJM does not agree there needs to be data link requirements between the RC and the PC, TP, LSE and DP to monitor and control the electric system in real-time. Both the TP and PC do not have the real-time data necessary to monitor the system, and therefore, data links are not needed. Specific to the LSE and DP, their real-time data is provided directly to their TOP or TO.
Response: The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision.		
Hydro One	No	R-1 contains what appears to be a redundant P-81 type of issue between what is in COM-001-2 and this standard- Interpersonal Communication vs. Voice Communication. These requirements could introduce a double jeopardy issue for non-compliance and should be revisited by the drafting team and further explanation provided prior to support.
Independent Electricity System Operator	No	We agree with all the requirements except R1. Requirement R1 appears to be largely redundant with Requirement R1 of COM-001-2. Requirement R1 of COM-001-2 requires each Reliability Coordinator to have Interpersonal Communication capability with the TOP and BA within the RC area and with each adjacent RC within the same Interconnection. By definition, Interpersonal Communication is “Any medium that allows two or more individuals to interact, consult, or exchange information.” The difference between the two requirements appears to be the omission of Generator Operator in COM-001-2, which can be added to totally eliminate the redundant IRO-002-4 R1. We suggest the SDT consider presenting this option to the Standards Committee to initiate appropriate actions to avoid adding a P81 candidate.

Organization	Yes or No	Question 2 Comment
Response: The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions.		
INDN - Independence Power & Light	No	Requirement R1 is very similar to Requirement R1 of COM-001-2 which requires the Reliability Coordinator to have Interpersonal Communication capabilities with the exception that COM-001-2 does not include a requirement for RC to have comm links with GOPs. For Paragraph 81 considerations, the two standards should be reconciled such that only one requirement is needed. INDN supports the comments submitted by Southwest Power Pool regarding Requirement R2. Requirement R5 requires a 'redundant and highly reliable infrastructure' for the exchange of data. There is some confusion as to whether this statement refers to redundant circuits providing data to a Control Center EMS or refers to an independent backup center as required by EOP-008. If in fact the infrastructure referenced is a backup center, then R5 is redundant and should be eliminated from the standard. Clarification is needed to resolve this question.
Response: 1. The SDT agrees that Requirement R1 is redundant with proposed COM-001-2 and has deleted the requirement. Any questions as to applicability of entities for this type of requirement were decided in the industry discussions for proposed COM-001-2. See summary consideration for revisions. 2. Please see response to Southwest Power Pool. The SDT has deleted the term 'and highly reliable' as it is unmeasurable. See summary consideration for revision.		
Electric Reliability Council of Texas, Inc.	No	ERCOT does not agree with the rationale for deleting R2 of IRO-002-3. EOP-008 is an emergency operating plan for loss of primary control center functionality. Most instances of the situations that R2 applied to are not emergency situations, but for

Organization	Yes or No	Question 2 Comment
		having alternative means of accomplishing required reliability tasks during the timeframe that analysis tools may be unavailable.
Response: The SDT felt that Requirement R2 of proposed IRO-002-3 was vague and decided to draft Requirement R3 of proposed IRO-002-4 which gives the responsibility and authority for any planned maintenance or outages of monitoring/analysis tools to be approved by the System Operator. No change made.		
Texas Reliability Entity	No	1) R4: Recommend replacing "to determine any potential System Operating Limit..." with "to determine any existing (pre-Contingency) and potential (post-Contingency) System Operating Limit... “. This change would be consistent with the terminology used in the proposed definition of Real Time Assessment. 2) R5: Recommend establishing a bright line criteria, such as: "fully redundant" and "a highly reliable infrastructure with end-to-end availability in each system of 95% or greater.” Also recommend technical guidance to provide more clarity on the intent for monitoring alarm management and awareness systems. As written, R5 does not meet the quality criteria of clear and unambiguous language (as identified in NERC's "Acceptance Criteria of a Reliability Standard: Quality Objectives", item 8). From a compliance and enforcement perspective it is difficult to measure "giving particular emphasis" and "highly reliable infrastructure".
Response: 1) The SDT feels that pre-Contingency or post-Contingency are contained in the definitions of SOL and IROL and adding that language would create redundancy with the current language of monitoring SOL and IROL exceedances. No change made. 2) The SDT has deleted the term ‘and highly reliable’ as it is unmeasurable. See summary consideration for revision. While the SDT understands that the commenter may feel that the terms are vague, the SDT believes that it places the proper emphasis on the conditions and allows for professional and technical judgment to be employed to satisfy the requirement thus allowing for maximum flexibility on the part of individual entities to tailor the solution to best fit its individual needs. No change made.		

Organization	Yes or No	Question 2 Comment
NV Energy MidAmerican Energy	No	R2: Regarding data links with a variety of entities, we see no reliability rationale for requiring data links with Planning Coordinators, Transmission Planners, Load Serving Entities, or Distribution Providers. With the first two, there is no call for real time data; for the others the data for LSE and DP entities normally routes through the host TOP or BA, which is where the data link requirement should solely reside. Recommend deletion of “Load Serving Entities, or Distribution Providers.” R3: As written, it is unclear whether the authority to approve planned outage and maintenance of its monitoring and analysis capabilities extends to RC personnel other than the Operators alone. Also, the authority to approve does not literally mean that the RC Operator “must” approve; therefore, there may be an unintended consequence that such maintenance work could be performed without RC approval. R5: The phrase “over a redundant and highly reliable infrastructure” is rather imprecise. Suggest replacing this phrase with “over a system that is not interrupted by a single point of failure”.
Response: R2. The SDT agrees and has changed the wording of Requirement R2. See summary consideration for revision. As written, and as the SDT intended, the requirement applies only to System Operators. If maintenance work was performed without the approval of the System Operator, the entity would be in violation of this requirement. No change made. The SDT has deleted the term ‘and highly reliable’ as it is unmeasurable. See summary consideration for revision.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

3. **Do you agree with the changes made to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration:

Several commenters noted the discrepancy between the language in the Rationale Box for Requirement R6 and the requirement itself. The language in the Rationale Box was modified to bring it in line with the requirement.

Several commenters pointed out what they felt was a potential discontinuity between the 30-minute criterion in Requirement R5 and the 2-hour allowance provided in approved EOP-008-1, Requirement R5. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement. Specifically, approved EOP-008-1 requirements address:

1.2.1 Tools and applications to ensure that System Operators have situational awareness of the BES.

1.6.2 Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of 'Real-time Assessment' do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa. The SDT did modify the requirement language to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts.

Many commenters posed questions regarding daily Operating Plans. Although no changes were made to the requirements as a result of those comments, the SDT offered the following to clarify the intent of the SDT. An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Analysis or a Real-time Assessment. As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the Operational Planning Analysis. When a Reliability Coordinator performs an Operational Planning Analysis, the analysis may reveal instances of possible SOL and IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for the day-to-day SOL or IROL exceedances identified in the Operational Planning Analysis are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of 'the Operating Plan document' for compliance purposes.

Numerous commenters suggested combining Requirement R2 with other requirements or simply deleting it altogether. The SDT chose to delete it as indicated below.

Several commenters suggested language changes for Requirement R7 which the SDT subsequently deleted in lieu of proposed IRO-001-4 Requirement R1.

Other comments suggested modifying the 'NERC registered entity' terminology in Requirement R4 and the use of the term 'Reliability Coordinator Wide Area' in Requirement R1. Both of these terms were modified.

The rest of the comments received were single comments and are addressed individually below.

The SDT has made the following changes due to industry comments:

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

R2.

R3. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R4. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).

R5. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

R7.

Data retention: Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R4, R6 through R8 and Measures M1 through M4, M6 through M8 for a rolling six month period for analyses, the most recent 90 days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R5 and Measure M5 for a rolling 30 calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, but the standard refers to a revised definition of "Operational Planning Analysis". Suggest keeping the Purpose of IRO-008-1. The proposed Purpose in IRO-008-2 does not adequately introduce what the performed analyses and assessments are performed on.
Response: The SDT agrees and has made the suggested change. The SDT does not believe that the suggestion adds clarity. No change made.		

Organization	Yes or No	Question 3 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	As defined, the term "Operating Plan" refers to a formal document or plan must be submitted. There are existing other requirements and processes in place within our region that provide the necessary data (via automated tools) to perform the next-day study. Requiring a submission of an "Operating Plan" would require the data to be manually entered and result in additional man-power usage with no benefit to reliability. We recommend the following language: "Each Reliability Coordinator shall review the operating data for next-day operations provided by its Transmission Operators and Balancing Authorities." R3 - This requirement implies a formal "Operating Plan" must be produced each day. See comments for IRO-008-2 R2 above. We recommend the following language: "Each Reliability Coordinator shall document the coordination of actions for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the data for the next-day provided by its Transmission Operators and Balancing Authorities." R4 - What does "impacted" mean and why is it not limited to entities who are required to take action (TOPs, BAs, GOPs, etc.)? R6 - Is this meant to refer to the Operating Plan developed in R3? Need clarification. Rationale for R6 discusses use of the term Emergency, yet the term is not used in R6 or R7. The words "as indicated in its Operating Plan" add no value to the statement requiring notification to the named entities. Recommend deletion. R7 - Change "to deal with" to "to prevent or mitigate." Add clarification because the TOP and BA are also issuing Operating Instructions. It should be clear that the RC is a back stop for TOP and BA. R8 - Same as R6. Delete "as indicated in its Operating Plan".

Organization	Yes or No	Question 3 Comment
		Compliance section 1.3 - Data Retention: Recommend changing “the most recent three months for voice recordings” to “90 days” to eliminate disparity with non-30 day months. This also will allow automation of deletion processes. It will also make the second paragraph match the third paragraph which requires 90 days for R5 voice recordings.

Response: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes. No change made.

R3 – The response to your comment concerning Operating Plan above addresses your concern for the development of a daily Operating Plan in Requirement R3. No change made.

Organization	Yes or No	Question 3 Comment
R4 - Impacted goes beyond the concept of those entities that have an active role to play in the Operating Plan. It also includes those entities which may not have an active role to play in the plan but are still impacted by the given operating condition. For example, an entity may have Load impacted by a given situation and the only available option that entity may have is to shed that Load. But if the plan doesn't call for that entity to shed the Load, then the entity doesn't have an active role in the plan but is still impacted by the situation and therefore is deserving of notification. However, the SDT has deleted 'NERC registered' due to comments received. See summary consideration for revision. R6 - Yes, the Operating Plan is the Reliability Coordinator's plan developed in Requirement R3. The 'its' is intended to point back to the Reliability Coordinator developing the plan. No change made. The 'Emergency' references in the Rationale Box for Requirement R6 have been deleted for consistency. The phrase 'as indicated in its Operating Plan' limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator's Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made. R7 – The SDT has deleted Requirement R7 as duplicative of proposed IRO-001-4, Requirement R1. See the summary consideration for the revision. Regarding your comment requesting clarification in the standard because the Transmission Operator and Balancing Authority also issue Operating Instructions, it is true that overlap does exist between the Reliability Coordination and Transmission Operator roles as well as between the roles of the Reliability Coordinator and the Balancing Authority. However, the clarification for that functionality is found in the Functional Model not in the reliability standards. The IRO standards are Reliability Coordinator based. Transmission Operator actions are covered in TOP standards. Likewise, the BAL standards, as well as some TOP standards, cover the requirements for Balancing Authorities. While the roles of the Reliability Coordinator and Transmission Operator are very similar, the scopes are considerably different. The Transmission Operator is responsible for reliably operating within its Transmission Operator Area whereas the Reliability Coordinator is responsible for a wide-area view which may encompass several Transmission Operator Areas. Both functions have the authority to direct other functional entities within its respective area to ensure reliable operations. A similar situation exists between the Reliability Coordinator and the Balancing Authority. It takes a shared, coordinated effort among all three entities to maintain reliability. No change needed with the deletion of the requirement. R8 – See our response to your comment regarding deleting the phrase 'as indicated in its Operating Plan' in R6 above. The SDT has updated the Compliance section with the latest approved language.		

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	The NSRF does not concur with 1) the RC having Operating Plans for next day operations (per R2) as stated in TOP-002-4, R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities... Plus 2) the notification of NERC Registered Entities identified in those plans. The NSRF does not know, for example, how having a requirement to inform someone of an Interchange schedule that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have an Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the IERP only recommends this and it is not a FERC directive or remove Operating Plans and replace with "plans". R5, see question 11 concerning the 30 minute threshold

Response: 1) The Reliability Coordinator is not required to have such an Operating Plan as in proposed TOP-002-4. The Reliability Coordinator is required to have an Operating Plan per Requirement R3 of proposed IRO-008-2. The requirements that you mention in Requirements R4 and R5 are in proposed TOP-002-4 and are intended for the Balancing Authority not the Reliability Coordinator. An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration

Organization	Yes or No	Question 3 Comment
process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. 2) The essence of Requirements R4 and R5 in proposed TOP-002-4 is that Parts 4.1-4.4 should be considered by the Balancing Authority in the development of its Operating Plan for the next-day. If in the development of that plan, the Balancing Authority determines that the interchange schedule mentioned may need to be modified to address a given situation, then the Balancing Authority must notify you of the potential change such that you can be prepared to make the change. No change made. The SDT has modified the notification requirement in Requirement R4 by deleting the qualifier 'NERC registered'. There may be entities needing notification other than Balancing Authorities and Transmission Operators which the Reliability Coordinator normally communicates with. There may be situations where all of these entities are not specifically NERC registered, especially in Canada. See the summary consideration for the revision. R5 – The SDT was charged with considering a number of factors in its deliberations regarding the TOP/IRO package of standards. One of those factors was the directives issued by FERC in the NOPR. Another was the recommendations of the IERP. Both were taken to heart. The inclusion of Requirements R4 and R5 in proposed TOP-002-4 is intended to be a continuation of the separation of responsibilities for the Balancing Authority and Transmission Operator which had not appeared in previous versions of the standards. You will notice a considerable paralleling between the Transmission Operator and Balancing Authority as well as between the Transmission Operator and Reliability Coordinator. That being the case, Requirement R5 will not be deleted. (See our response in 1) above to your suggested proposal to delete R5.)		

Organization	Yes or No	Question 3 Comment
The SDT believes your reference to Question 11 concerning Requirement R5 is actually a reference to your response to Question 7. Please see our response to your comments in Question 7.		
Colorado Springs Utilities	No	1. R6 rationale says that “exceedance” was changed to “emergency” but the standard shows no change. 2. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 3. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities.
Response: 1. The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision. 2. & 3. – Timing requirements requested for Requirements R6 and R8 are already provided for in other standards. For example, if an IROL is exceeded, the applicable entities must act to mitigate the exceedance within the IROL’s T_v (approved IRO-009-1 Requirement R4 and proposed TOP-001-3 Requirement R12). Similar requirements are provided for SOLs in proposed IRO-008-2 Requirement R7 and proposed TOP-001-3 Requirement R14 and the associated SOL whitepaper. The standards specify that applicable entities must operate within SOLs and IROLs. To comply with these standards timely notifications of all impacted entities must be made. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	1) In R6, the wording does not reflect the changes in the rationale. ‘Exceedance’ has not been replaced with ‘emergency’. Did this change occur as result of multiple revisions in the draft? Current: “Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.” Suggested: “Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results

Organization	Yes or No	Question 3 Comment
		of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) emergency within its Reliability Coordinator Wide Area." 2) In the R5 VSLs, there is concern that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Suggestion: expand bandwidth. 3) In R8, replace "prevented or mitigated" with "addressed". Current: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated." Suggested: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been addressed."
Response: 1) The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision. 2) Please refer to Question 14 for the SDT's responses to VSL comments. 3) The proposed wording change introduces ambiguity into the requirement. The existing wording is clear and straight forward in that a potential exceedance has been prevented or an actual exceedance has been mitigated. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	By the various uses of "Operating Plan" in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? Southern believes IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded as it will require RCs to produce

Organization	Yes or No	Question 3 Comment
Company Generation; Southern Company Generation and Energy Marketing		an email response to all TOP and BA operating plans stating "reviewed". RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, Southern recommends removing requirement R2. As mentioned above, the use of Operating Plan in R6 is confusing. Does the SDT consider this to be a single continuously updated Operating Plan or does the SDT expect this to have been an Operating Plan developed for next day assumptions which then transitions into a different Operating Plan when a real time condition is observed? Also, as currently drafted, R6 is very confusing. Southern proposes rewording R6 to move the "as indicated in its Operating Plan" statement to the end to add clarity and eliminate confusion. "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area as indicated in its Operating Plan." For R7 and R8, consider the example where the RC and a TOP see a potential SOL in their real time assessments and coordinate with one another on a post contingency plan to address the issue. As time passes and system conditions change, the contingency issue no longer exists. These requirements create an administrative burden on RCs to notify the TOP if the contingency issue has subsided without ever having to implement a plan. A more realistic requirement would be for the RC to notify the TOPs/BAs that are having to reconfigure their system or re-dispatch generation to resolve an SOL issue when the SOL has been prevented or mitigated. Southern suggests rewording R7 and R8 to remove the administrative burden of notifications when no action was taken by a TOP/BA.

Organization	Yes or No	Question 3 Comment
Response: R1-R8 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. R2 – Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision. R6 – Regarding your comment on Requirement R6 and Operating Plan, please refer to our response to your concern about Operating Plan in Requirements R1-R8 above.		

Organization	Yes or No	Question 3 Comment
R6 – Regarding your suggested wording for Requirement R6, the phrase ‘as indicated in its Operating Plan’ limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator’s Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made. R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision. R8 – Regarding your request to direct the notification in Requirement R8 to only those entities required to take action to prevent or mitigate an exceedance is well and good; however, it leaves out the entities which truly may only be impacted by the operating condition but do not have an active role to play in the mitigation plan. These entities deserve notification because the situation could mean that the impacted Load is at risk. Likewise they deserve notification when the situation has been cleared. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify “in accordance with its SOL Methodology” so that the breadth of contingencies to be studied is known.
Response: See SDT’s response to FRCC’s comments. The SDT believes the requirement as written is clear. Furthermore, the SDT believes that not exceeding any of “its” limits would require the entity to have its ratings set by their SOL methodology in conformance with current NERC standards. No change made.		
Duke Energy	No	R1: No Comment R2: Duke Energy believes that this requirement, as written, would be an administrative burden on the RC to review all Operating Plans of a TOP and BA within their RC area. We suggest removing R2 or combining R2 and R3 because coordination of SOL(s) and IROL(s) and their mitigation plans would not exist without the RC reviewing the plans of the TOP and BA. In addition, we believe duplicative evidence would be provided for both R2 and R3 which is why we suggest combining the two requirements or removing R2 entirely. R3: See comment for R2

Organization	Yes or No	Question 3 Comment
		R4: Per the Functional Model, the RC would only notify impacted TOPs and BAs as to their role in the Operating Plan. Using NERC registered entities goes against the roles defined in the Functional Model and Duke Energy suggests rewording as follows: ”Each Reliability Coordinator shall notify impacted BA(s) and TOP(s) identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).”In addition, the coordinated plans identified in R3 are only the coordinated plans provided by the TOP(s) and BA(s) in its RC area. R5: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC’s transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC to transition to its backup control center. If a RC is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R6: Requiring the RC to notify the TOP(s)/BA(s) on every exceedance of an SOL may be burdensome and will be operationally distracting to the current role of the RC which is having a wide area view of their RC area. R7: See comment for R6. The requirement, as written, presumes the TOP/BA will fail to act. We believe the RC should take actions only when either the TOP/BA failed to act or if the RC disagreed with the mitigating plans of the BA/TOP. As such, we suggest the following language revision: ”Each Reliability Coordinator shall validate that the actions in the TOP(s)/BA(s) Operating Plan are appropriate and issue Operating Instructions, as necessary if: o The TOP/BA fails to implement the Operating Plan o The RC determines that the TOP/BA Operating Plan is insufficient”

Organization	Yes or No	Question 3 Comment
		Duke Energy believes this language better aligns with the proposed TOP-001-3 R13 that already requires the TOP to notify and share their Operating Plan used to mitigate SOL(s) with the RC. The RC should only be responsible for validating the TOP(s) Operating Plan and taking action if, and only if, the TOP fails to act or the RC deems the actions taken by the TOP are insufficient. R8: See comment(s) for R6 and R7.

Response: R1 – Thank you for your support.

R2 - Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision.

R3 – See the response to Requirement R2 above.

R4 – The SDT agrees with your comment; however, there may be situations where entities other than Balancing Authorities and Transmission Operators may be identified to take an active role in an Operating Plan. However, the SDT has deleted 'NERC registered' due to comments received. See the summary consideration for the revision.

R5 –The SDT has revised the wording of Requirement R5 based on your comments and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Organization	Yes or No	Question 3 Comment
The 30-minute requirement and the definition of “Real Time assessment” does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC’s contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. R6 – Reliability Coordinators are already required to notify Balancing Authorities, Generator Operators, and Transmission Operators when there is an actual or expected condition whereby an SOL or IROL is exceeded. Please reference approved IRO-005-3.1a Requirement R6 and approved IRO-009-1 Requirement R4. Requirement R6 does not require any more from the Reliability Coordinator than is currently being requested. No change made. R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision. While deleting Requirement R7 eliminates the need for making language changes as proposed in your comment, the fact remains that the Reliability Coordinator, Transmission Operator and Balancing Authority all have the authority to issue Operating Instructions. Overlap does exist between the Reliability Coordinator and Transmission Operator roles as well as between the roles of the Reliability Coordinator and the Balancing Authority. However, the clarification for that functionality is found in the Functional Model not in the reliability standards. The IRO standards are Reliability Coordinator based. Transmission Operator actions are covered in TOP standards. Likewise, the BAL standards, as well as some TOP standards, cover the requirements for Balancing Authorities. While the roles of the Reliability Coordinator and Transmission Operator are very similar, the scopes are considerably different. The Transmission Operator is responsible for reliably operating within its Transmission Operator Area whereas the Reliability Coordinator is responsible for a wide-area view which may encompass several Transmission Operator Areas. Both functions have the authority to direct other functional entities within its respective area to ensure reliable operations. A similar situation exists between the Reliability Coordinator and the Balancing Authority. It takes a shared, coordinated effort among all three entities to maintain reliability. No change needed with the deletion of the requirement. R8 – See the SDT response to your comments on Requirements R6 and R7 above.		

Organization	Yes or No	Question 3 Comment
Bureau of Reclamation	No	Reclamation suggests that R4 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
Response: Based on your and other comments on the use of 'NERC registered entities', the SDT proposes to delete 'NERC registered' and modify the requirement to reflect the relationships among the Reliability Coordinator and its Balancing Authorities and Transmission Operators. See the summary consideration for the revision.		
SPP Standards Review Group INDN - Independence Power & Light	No	Hyphenate 'next-day' in Requirement R1. We suggest slightly rewording Requirement R3 to read: 'Each Reliability Coordinator shall have a coordinated Operating Plan(s) for the next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities in Requirement R2.' Requirement R5 requires a Real-time Assessment be performed at least once every 30 minutes. This is technically infeasible in some situations where there is missing data and/or the state estimator does not solve properly. An assessment cannot be completed under these conditions. Being a zero tolerance standard, this sets the industry up to fail. One of the largest categories of events being reported under event analysis is EMS or state estimator outages. Additionally, even if the state estimator does solve, can we be assured that the solution is correct in these situations? Also, just because the state estimator has solved doesn't necessarily mean that each contingency in RTCA is a valid solution. The language needs to be modified to reflect this situation. Perhaps the requirement should be focused on a normal schedule for a Real-time Assessment every 30 minutes but consideration would be given for situations where the tools that are currently available to the industry simply cannot provide the desired outcome. If the standard maintains the 30 minute or some similar time frame requirement, logging the completion of those assessments and

Organization	Yes or No	Question 3 Comment
		maintaining records will prove to be burdensome to the industry requiring additional personnel simply to staff this capability. This argument applies to the Transmission Operator in TOP-001-3, Requirement R13. Replace 'Real-Time' with 'Real-time' in Measure M5.

Response: Your suggested change to Requirement R1 has been made. See the summary consideration for the revision.

Your suggested change to Requirement R3 has been made. See the summary consideration for the revision.

The SDT has altered Requirement R5 to address your concern and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The 30-minute requirement and the definition of "Real Time assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. See the summary consideration for the revision.

Your suggested change to Measure M5 has been made. See the summary consideration for the revision.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) For Requirement R1, there is an incorrect glossary term listed. The term should be "Reliability Coordinator Area" not "Reliability Coordinator Wide Area." There is no listing of any new proposed terms, so this needs to be aligned with the correct term in the NERC glossary. (2) Requirement R3 is wordy and leads to confusion. There is no need to cross reference R1 and R2, as this is a natural succession of requirements. This requirement should be combined with R1. (3) Requirement R4 should be combined with R1. (4) Requirement R5 should be combined with R1. (5) The drafting team should reevaluate this standard and consider options to consolidate and combine requirements. There are several areas stated above that could be grouped together into a single requirement or fewer requirements that would still meet the purpose of the standard.
Response: (1) The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision. (2) Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision. With the deletion of Requirement R2, there is a need to keep the reference to consideration of Operating Plans provided by Balancing Authorities and Transmission Operators. (3), (4), & (5) Combining multiple, distinct activities into a single requirement creates issues when developing VSLs. The VSLs become multi-layered, increasing their complexity. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word "Emergency". The Rationale box suggests that the

Organization	Yes or No	Question 3 Comment
		language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word “Emergency” is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addressed as soon as possible without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to “Emergency”, which should be corrected. Comment on R1: Replace ‘or’ with ‘and’. Comment on R5: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications, specifically a contingency analysis tool. R2 - The concept of an RC review of each TOP and each BA’s OPA seems questionable from a practical perspective. M2 requires proof of such an action. While RCs may indeed screen some of the more important OPAs, why must the RCs look at them all? And worse, why must that proof be retained?

Response: The Rationale Box for Requirement R6 has been changed for consistency. See the summary consideration for the revision.

The term ‘Emergency’ does not appear in the VSLs for Requirement R6. No change made.

Your suggested change to Requirement R1 has been made. See the summary consideration for the revision.

There is nothing in the definition of Real-time Assessment that limits the platform for conducting the evaluation of Real-time system conditions to a Contingency analysis tool, i.e. an RTCA tool.

Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator’s Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities

Organization	Yes or No	Question 3 Comment
and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area. See the summary consideration for the revision.		
Georgia System Operations Georgia Transmission Corporation	No	By the various uses of "Operating Plan" in Requirements 1 through 8, does the SDT consider this to be a single continuously updated operating plan or does the SDT expect an Operating Plan to be developed for next day assumptions which then transitions into a different operating plan when a real time condition is observed? GSOC agrees with its RC that IRO-008-2 Requirement 2 will pose an administrative burden on the Reliability Coordinator as it is currently worded. It will require RCs to produce an email response to all TOP and BA operating plans stating "reviewed". RCs are required to have a coordinated Operating Plan considering the Operating Plans provided by its TOPs and BAs in the proposed R3. In order for the RC to develop an Operating Plan, as required by R3, the RC must review its TOPs and BAs plans; therefore, making R2 unnecessary.
Response: R1-R8 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances		

Organization	Yes or No	Question 3 Comment
identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made. Based upon your and other comments the SDT proposes to delete Requirement R2 as it is duplicative with Requirement R3 which requires the Reliability Coordinator's Operating Plan to be coordinated with the Operating Plans provided by its Balancing Authorities and Transmission Operators. That plan cannot be coordinated without reviewing the plans of the Balancing Authorities and Transmission Operators within the Reliability Coordinator's Area.		
ReliabilityFirst	No	ReliabilityFirst submits the following comments for consideration: 1. Requirement R7 - The phrase "as necessary" is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. RF suggests removing the phrase "as necessary", which is vague and creates concerns similar to those expressed by the Commission in Order 791. In Order 791, the Commission supported the RAI's goal to develop a framework for the ERO Enterprise's use of discretion in the compliance monitoring and enforcement space, but rejected the codification of "identify, assess, and correct" language within the CIP Version 5 Reliability Standards because it is vague. ReliabilityFirst is also concerned that the qualifier "as necessary" codifies discretion within IRO-008-2. ReliabilityFirst believes that neither discretion nor controls should be codified in Reliability Standards. Rather, the ERO Enterprise should utilize discretion in the compliance monitoring and enforcement space when determining the relevant scope of audits and whether to decline to pursue a noncompliance as a violation. With the RAI, the ERO Enterprise is developing a singular and uniform framework to inform the ERO Enterprise's use of discretion in the compliance monitoring and enforcement space. Therefore, ReliabilityFirst recommends removing the qualifier "as necessary" from R7 and allow the ongoing RAI effort to create a

Organization	Yes or No	Question 3 Comment
		meaningful and unambiguous framework that the ERO Enterprise will utilize to inform its use of discretion in the compliance monitoring and enforcement of all Reliability Standards. ReliabilityFirst cautions that codifying discretion in some Reliability Standards may create confusion once the ERO Enterprise begins to implement the RAI and its discretion in compliance monitoring and enforcement work. For example, there may be confusion of whether discretion codified in certain Requirements of Reliability Standards precludes the ERO Enterprise's use of RAI discretion for those Requirements where discretion is not codified. ReliabilityFirst offers the following for consideration: "Each Reliability Coordinator shall issue Operating Instructions, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6."
Response: The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.		
American Transmission Company	No	R1 - Although proposed IRO-008-2 is not applicable to ATC, ATC suggests the removal of the word "Wide" from the term "Reliability Coordinator Wide Area" in Requirement R1. "Reliability Coordinator Wide Area" is not currently defined, nor proposed for inclusion in NERC's Glossary of Terms.
Response: The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision.		
David Kiguel	No	R4: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.

Organization	Yes or No	Question 3 Comment
Response: Thank you for reminding us of operating differences across our northern border. Based on your and other comments on the use of 'NERC registered' the SDT decided to modify the language in Requirement R4 to 'notify impacted Balancing Authorities, Transmission Operators and other entities identified in the Operating Plan(s)'. See the summary consideration for the revision.		
PJM Interconnection	No	Please see PJM's comments included in Question #12.
Response: Please see response to comments in Question 12.		
Consumers Energy	No	R6, R7, R8 - The Rationale says that "IROL exceedance" was replaced with "emergency", but "emergency" does not appear in the Requirement; "IROL exceedance" does. It doesn't appear that SDT did what they claim.
Arizona Public Service Company	Yes	IRO-008 R6: The Rationale box says that the "language changed from IROL exceedance to Emergency..." But the language in the draft standard actually uses IROL exceedance and not Emergency
Response: The 'Emergency' references in the Rationale Box for Requirement R6 have been deleted for consistency. See the summary consideration for the revision.		
Independent Electricity System Operator	No	We agree with all the proposed changes except we find a discrepancy between the rationale for Requirements R6 and R7, and between Requirement R6 and its VSL with respect to the use of the word "Emergency". The Rationale box suggests that the language in R6 has been changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency. However, we see that both R6 and R7 continue to make reference to SOL or IROL exceedance, and the word "Emergency" is not used. In fact, we support keeping the SOL or IROL language in the two requirements since either can occur before an entity declares or enters into an Emergency, but the anticipated or actual SOL/IROL exceedance must be addresses as soon as possible

Organization	Yes or No	Question 3 Comment
		without delays as supported by R6 and R7. Hence, we suggest the SDT to keep the language in R6 and R7, and revise the Rationale box accordingly. Also, the LOWER VSL for R6 makes reference to “Emergency”, which should be corrected.
Response: The ‘Emergency’ references in the Rationale Box for Requirement R6 have been deleted for consistency. See the summary consideration for the revision. The term ‘Emergency’ does not appear in the VSL for Requirement R6. No change made.		
Electric Reliability Council of Texas, Inc.	No	The reference in R6 and R8 to “as indicated in its Operating Plan” is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly that can cause a “plan” to vary and the impacted entities to vary. That phrase should be deleted. In R7, “to deal with” should be replaced with “to prevent or mitigate”. In R2-R3, the current definition of Operating Plan states “a document”. While this context is appropriate for processes/procedures determined well in advance of real time. The timeframe described is really next day and while most “Operating Plans” are documented, all plans to operate reliably may not be documented or in “a document”. The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having “a document” rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single “document” and have several required elements. This can be overly prescriptive and burdensome. R4 further should not be limited to verbal or written notification if it remains. Some “plans” could be to commit additional generation. In the day-ahead process, the “notification” could occur via systems or other equivalent means. The connotation of

Organization	Yes or No	Question 3 Comment
		a "document" and "notification" identifying "roles" creates a layer of inefficiencies and manual administrative actions that are unnecessary if the planning and notification occurs via other means. R5 does not have any context surrounding it if an entity loses real time tools it utilizes to conduct a Real Time Assessment. It should not be a violation if an entity has analysis tool outages that cause a reasonable time deviation from a normal 30 minute timeframe. For example, if real time tools are not available some effort is given by System Operators in troubleshooting and corrective actions to make the real time tools available again. For example, by allowing 45-60 minutes as an alternative means, like conducting offline studies, is more reasonable to allow time for initial troubleshooting, then a decision to run the offline study, then to actually conduct the offline study without a violation for an abnormal situation that is still handled in a reliable fashion. While the current requirement has 30 minute requirement, IROLs are typically determined ahead of time or are so specific that the N-1 limit may still be valid if system topology has not changed thus allowing for continual Real Time Assessment even if the tool is unavailable temporarily. The introduction of SOL for the 30 minute Real Time Assessment introduces a new challenge relative to that of Real Time Contingency Analysis for thermal and voltage exceedances and all of the Facilities it takes into account vs the limited ones for IROLs. Currently proposed R8 is problematic for the ERCOT RC as potential SOL exceedances may show up as post contingency thermal facility rating exceedances that are then managed by the ERCOT Nodal market operations system as detailed in IRO-006-TRE. To notify a Transmission Operator that may or may not have to take a manual action depending on if the ERCOT Nodal market operations system resolves the SOL exceedance, would be unduly burdensome and result in a high volume of unnecessary communications. It should be explored as an alternative way to clarify somehow that it would be limited to actual "basecase" facility rating exceedances, not post contingency for thermal limits or for N-1 stability/IROL type exceedances. Alternatively, allow for the RC to identify when it would be appropriate to notify the

Organization	Yes or No	Question 3 Comment
		impacted entities and when not to in its Operating Processes and Operating Procedures to notify an entity. As it stands today, it is not feasible.

Response: R6-R8 – Regarding your suggested wording for Requirements R6 and R8, the phrase 'as indicated in its Operating Plan' limits the notification of other Reliability Coordinators to only those identified in a Reliability Coordinator's Operating Plan. Otherwise, all other Reliability Coordinators would have to be notified which would be excessive. No change made.

R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.

R2 & R3 – An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative

Organization	Yes or No	Question 3 Comment

burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes. No change made.

There is nothing in Requirement R4 which restricts the notification of a role in an Operating Plan to verbal or written communications exclusively. As indicated in the preceding comment, an Operating Plan contains a generic treatment of all the processes, procedures, and hardware and software systems that are at the operator's disposal. Those items could include specific provisions for notification of impacted entities. No change made.

R5 – The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30 minute criteria remains appropriate and important to maintaining BES reliability.

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The 30- minute requirement and the definition of "Real-time Assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is

Organization	Yes or No	Question 3 Comment
sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. See summary consideration for revision. R8 – As mentioned in the response to your concerns regarding Operating Plans in Requirements R2 and R3 and your concern regarding notification in Requirement R4, specific concerns addressing unique situations within the ERCOT market could be treated accordingly in the Operating Plan. No change made.		
Texas Reliability Entity	No	1) R3: Recommend replacing "to address potential System Operating Limit..." with "to address any anticipated (pre-Contingency) and potential (post-Contingency) System Operating Limit...". This change would be consistent with the terminology used in the proposed definition of Operational Planning Analysis. 2)R4: From the compliance and enforcement perspective it is important to know if the RC is required to notify impacted entities on a daily basis for Operating Plans that have extended impact (e.g. An Operating Plan based on an outage lasting a week) or just at the beginning? What is the intent of the SDT?
Response: R3 – The SDT feels that pre-Contingency and post-Contingency are contained in the definitions of SOL and IROL and adding that language would create redundancy with the current language of monitoring SOL and IROL exceedances. Please refer to the SDT's whitepaper on SOL Definition and Exceedance Clarification for additional information regarding the SDT's intent with regard to the SOL concept. R4 – Daily notifications would not be required for conditions which create an extended impact situation. The Reliability Coordinator would have notified the responsible entities of the condition upon identification. The responsible entity would be correct in assuming that the condition continues to exist until it is notified in Requirement R8 that the condition has been prevented or mitigated.		
MidAmerican Energy	No	Specific to IRO-008-2, R5, MidAmerican is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. MidAmerican recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period

Organization	Yes or No	Question 3 Comment
		when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address: • **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. • **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The 30- minute requirement and the definition of "Real-time Assessment" does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC's contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. In addition, the VSLs have been changed to reflect such concerns. See summary consideration for revisions.		
Peak Reliability	Yes	o R1 - "...planned operations for the next day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Wide Area" should be "planned operations in its Wide Area for the next

Organization	Yes or No	Question 3 Comment
		day will exceed System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLs) within its Reliability Coordinator Area” o R5: Language should be added to this Requirement to allow for tool outages. Adding “when tools are operating as expected” is an option. o R7: this Requirement is duplicative of IRO-001-4 R1. Although R7 is more specific than IRO-001-4 R1, R7 is covered by IRO-001-4 R1.

Response: R1 – The SDT has deleted Reliability Coordinator from the Reliability Coordinator Wide Area term. See the summary consideration for the revision.

R5 – The SDT has altered the requirement to address your concern and those of others. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s loss of control center functionality Operating Plan. The SDT believes that the TOP-001-3, IRO-008-2 and EOP-008-1 Requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, EOP-008-1 Requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The 30- minute requirement and the definition of “Real-time Assessment” does not specify the manner in which an assessment is performed nor does it preclude RCs and TOPs from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the TOP could rely on the RC to perform a Real-time Assessment or even review their RC’s contingency analysis results when their tools are unavailable and vice-versa. The SDT did modify the requirement language to changes “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform an RTA and determined that the modified language is sufficient to coordinate with the existing requirements of standard EOP-008 and should not introduce any requirement timing conflicts. In addition, the VSLs have been changed to reflect such concerns. See summary consideration for revisions.

Organization	Yes or No	Question 3 Comment
R7 – The SDT has decided to delete Requirement R7 in lieu of the more generic IRO-001-4, Requirement R1. See the summary consideration for the revision.		
Salt River Project	Yes	This standard significantly increases the communications required from the RC on the results of data exchanges, Operational Planning Analysis results, etc. This increase in communication could cause confusion about what is a potential problem being communicated per the requirements or and what is a true real-time problem.
Response: Reliability Coordinators should already be notifying entities whenever 1) they have a specific role to play in any anticipated operating situation, 2) they are impacted by planned operations within its Reliability Coordinator Area, 3) there is an actual or expected condition whereby an SOL or IROL is exceeded, and 4) whenever those conditions creating the impact have been prevented or mitigated. With the proposed deletion of Requirement R2 due to other comments, Reliability Coordinators are not being required to provide any more notification/confirmation than currently required. No change made.		
PacifiCorp	Yes	
Dominion	Yes	
PPL NERC Registered Affiliates	Yes	
Bonneville Power Administration	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	

Organization	Yes or No	Question 3 Comment
EDP Renewables North America LLC	Yes	
Exelon Ccompanies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Hydro One	Yes	
NV Energy	Yes	
Response: Thank you for your response.		

4. **Do you agree with the changes made to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT changed the Implementation Plan for Requirements R1 and R2 from 10 months to 9 months. Most of the other comments received were about clarifications of the proposed language. The SDT has provided requested clarifications and in addition has made the following change based on industry comments – Planning Coordinator and Transmission Planner have been deleted from Requirement R3 as those entities do not fit in the data specification concept. While data is transferred between a Reliability Coordinator, Planning Coordinator, and Transmission Planner, it is done in a less structured, more informal, ad hoc basis as the data is needed as opposed to a regular, structured data transfer as set up by a data specification.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Similar to TOP-003, R1 and R2 VRFs should be Low, not Medium.
Response: Please see response to question 14.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1.1 - Does this mean a generic type of data required or a detailed list of data points? R3 - Why is LSE included with the planned retirement of LSEs? Why is TP and PC included in this requirement? The TP and PC horizon timeline does not fit within the Operations Planning horizon.
Response: Requirement R1, Part1.1 requires a detailed list of data points. R3 – There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date.		

Organization	Yes or No	Question 4 Comment
Planning Coordinator and Transmission Planner have been deleted from Requirement R3 as those entities do not fit in the data specification concept. While data is transferred between a Reliability Coordinator, Planning Coordinator, and Transmission Planner, it is done in a less structured, more informal, ad hoc basis as the data is needed as opposed to a regular, structured data transfer as set up by a data specification.		
Dominion	No	Dominion does not agree with the purpose statement as written. It infers that ensuring the RC has data necessary to monitor and assess the operation of its Reliability Coordinator Area will somehow prevent instability, uncontrolled separation, or Cascading outages. Dominion suggests revising similar to "To ensure the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area." Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline.
Response: The SDT believes that the Purpose Statement accurately reflects the goal of this standard. No change made. Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. Requirement R1, Part 1.3 refers to the periodicity of the data, i.e., how often the data must be supplied. Requirement R1, Part 1.4 refers to the deadline for the initial provision of the data point, i.e., when you need to respond to a new request for data. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services).

Organization	Yes or No	Question 4 Comment
		In addition, R1 should specify a "minimum" set of data requirements. This is especially apparent when protection system status is called out in 1.2, but the status of the Facilities being protected is not called out - which is more important to reliability? Due to the ambiguity of what is and is not included in R1, other SDTs for other standards were unwilling to accept that there is duplication (see comments to TOP-003 R1 and R2 for more detail). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards. As such, we propose the SDT develop a "minimum" set of data, notification, information, etc., requirements as an attachment to the standard. RCs can always specify more if so desired.
Response: See response to FRCC comments. The SDT believes that the requesting entity, in this case the Reliability Coordinator, is in the best position to know what it needs to preserve reliability. One size does not fit all here as each system is different. The requirement is written to respect that fact and to allow individual Reliability Coordinator's to craft the list as they see fit using its professional judgment. The Transmission Operator and Balancing Authority would always be able to suggest additional data points if the Reliability Coordinator did not request them initially. No change made.		
Duke Energy	No	R1: The proposed definition for Operational Planning Analysis clearly relates to condition for next-day operations. However, the time horizon identified in this requirement (next day to 1 year out) is beyond the scope of the definition. The proposed definition does not make reference to time horizons post next-day operations. In addition, the scope of R1 goes above and beyond the prevue of the RC as currently defined in the NERC Functional Model. . Duke Energy suggests removing Operations Planning and adding Real-Time Operations and Same-Day Operations. R2: Duke Energy suggest rewording R2 as follows: "The Reliability Coordinator shall distribute its data specification to Applicable entities that have data required by the

Organization	Yes or No	Question 4 Comment
		Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." The addition of "Applicable entities" will limit the data specification to only those entities that need to provide data to the RC. In addition, we have the same comment on Time Horizon as is stated in R1.R3: Suggest removing Operations Planning Horizon for the reasons mentioned above.
Response: The data specification is set up in advance in order for the Reliability Coordinator to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made. The SDT does not believe that the suggested change adds clarity. No change made. The Time Horizon for Requirement R3 is written to acknowledge the fact that there will probably be different data streams for operations planning and Real-time or same-day operations. No change made.		
BC Hydro and Power Authority	No	The new Requirement has the Reliability Coordinator able to ask for "sub-100 kV' data if it deems necessary. This is an increase in scope from the data the RC currently asks for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.		
SPP Standards Review Group	No	The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should be used to remove the Interchange Authority from the Applicability Section of TOP-003-3.

Organization	Yes or No	Question 4 Comment
		There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize 'Part' in the Rationale Box for Requirement R1.
Response: The SDT agrees and has removed Interchange Authority from proposed TOP-003-3. Ultimately, a point-by-point listing will be necessary, although the process may begin with a higher-level specification, such as "all line statuses, MW/MVAR flows and bus voltages for all transmission assets controlled by this Transmission Operator." It is doubtful that a Reliability Coordinator would necessarily know all of the points in detail for a Transmission Operator new to its Reliability Coordinator Area, but likely that it would know the listing of points for existing, mature Transmission Operators. No change made. The SDT agrees and has capitalized "Part" as suggested.		
ACES Standards Collaborators	No	(1) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (2) Requirement R2 should be combined with R1. A simple insertion of "maintain and distribute" in R1 would result in the same outcome with fewer requirements to comply with. (3) Requirement R3's language of "mutually agreeable" is challenging for compliance because it requires additional documentation to show that the data was submitted in a "mutually acceptable format." The requirement should be that entities must

Organization	Yes or No	Question 4 Comment
		submit the applicable data by the required timeline. The SDT has made a straight-forward process very complicated for compliance purposes.
Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. (2) The SDT believes that the distribution of the specification is a sufficiently different action from the creation of the specification that a separate requirement is justified. No change made. (3) "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	We agree with the proposed changes, but are unable to locate R1, Part 1.7 as indicated in the Rationale box above R1, that: "Proposed Requirement R1, part 1.7 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." We are therefore uncertain as to how the concerns raised in Paragraph 92 (and in the next several paragraphs) of the FERC NOPR are addressed.
Consumers Energy	No	R1 - The Rationale refers to a R1, part 1.7, but no such part exists in the posted draft.
Colorado Springs Utilities	Yes	1. Proposed Requirement R1, part 1.7 rationale does not reference the standards correctly and does not appear to belong to R1.
Response: The rationale box has been corrected to read "Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." This directly addresses Paragraph 92 of the NOPR.		
Rayburn Country Electric Cooperative	No	Similar to my comments on IRO-001 and TOP-001 I think this could be combined with TOP-003-3 in a similar manner. GROUP 1Any of the following: Reliability Coordinator

Organization	Yes or No	Question 4 Comment
		Balancing Authority Transmission Operator GROUP 2Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: (Maintain the use of general specifications only, detailed specificity can be within each functional entities published data specification) R2. GROUP 1 shall distribute its data specification to entities that have data required by GROUP 1 to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Volkmann Consulting	No	IRO-010 should have a 4th requirement that requires the RC to determine and communicate any deficiency of data received back to the applicable entity providing the data. R3 requires the sending of data to the RC, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the RC know if they have enough data, but performance of its real-time processes and tools. The RC should be required to communicate data deficiencies and not rely on the Audit process.

Organization	Yes or No	Question 4 Comment
Response: The SDT believes that the requirements are written such that the onus for performance is on the Reliability Coordinator. Therefore, the Reliability Coordinator will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made.		
City of Garland	No	Requirement # 1Concern is with the portion of the definition of "Operational Planning Analysis" and "Real Time Assessments" that lists "identified phase angle". It is not clear what "identified" means. "Identified" should mean that the RC will identify representative points across the area for which the RC is responsible - not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
Response: The part of the definition that is referenced here is actually "… and identified phase angle and equipment limitations…" This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. No change made. If an entity does not have PMU data then this is not an issue. If an entity has PMU data, then the SDT believes that the entity will have built its systems to be able to handle the volume of data associated with the PMU data. The Reliability Coordinator is not going to request data just for the sake of having it and will only request data that it truly needs. This could assist in dealing with the volume of data going across the link. In addition, the requirement cites mutual agreeability which assures that the controlling entity can't request something that the submitting entity simply can't provide. No changes made.		
Ingleside Cogeneration LP	No	R1.1 allows the Reliability Coordinator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this limitation, we can see that the standard will be applied unevenly across Reliability

Organization	Yes or No	Question 4 Comment
		Coordinators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R3). The RC should provide those specifications and processes under Requirement R1 as is the case in the existing standard. If there is an issue with the term “mutually agreeable”, the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made. “Mutually agreeable” allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can’t force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made		
Idaho Power	No	I agree with the revisions to IRO-10-2 but have concerns with requirement 3. If the RC is willing to provide attestation that the requirement has been fulfilled it will be no problem. If the entity is required to provide evidence it will be more difficult. You could retain all the emails but how do you prove that was all the requests.
Response: The measure is written to allow for attestations to be provided as suitable evidence of compliance and the SDT believes that such attestations will be provided if requested. No change made.		
Liberty Electric Power, LLC	No	There are two types of data falling under the standard, and they should be treated differently in the requirements. Data requests are fine as written, but data transmitted automatically for real-time purposes should be handled with a separate requirement. The requirement should be for the data provider to provide the

Organization	Yes or No	Question 4 Comment
		specified data as required, but with a measure that shows the RTU or other data transmission device is installed and operational. There is no log of this data, and requiring an attestation is too burdensome for the RC, who may be required to provide hundreds of documents in response to the requirement.
Response: The requirements as written cover both unique data requests and regularly scheduled automatic data submittals. The Reliability Coordinator will be regularly and continually checking the data it receives and thus providing an attestation, if requested, should not be a burden. No change made.		
Electric Reliability Council of Texas, Inc.	No	Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems, will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: Protection Systems were added due to concerns raised in NOPR paragraph 78. The intent of such changes is to ensure that Reliability Coordinator can maintain an appropriate level of situational awareness. While the SDT believes that this will result in an additional burden on entities, it believes that this incremental increase is relatively minor and necessary for reliability. No change made. The SDT believes that the implementation time frame of 12 months is adequate. Nearly all, if not all, of the data that a Reliability Coordinator might need for reliability is already in place and telemetered to the Reliability Coordinator. The 12 month period will allow for any additional work that might be needed to be accomplished. Adoption of this standard does not create a massive new data transfer effort. No changes made.		

Organization	Yes or No	Question 4 Comment
Texas Reliability Entity	No	1)General: Recommend adding a Requirement 4 for RCs stating the RC shall notify entities that provided data per R2 when submitted data does not meet the specification and the nature of the deficiency. 2) R1: Use of the word "Provisions" in 1.2 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for TOP-003-3, R 1.2)
Response: 1) The SDT believes that the requirements are written such that the onus for performance is on the Reliability Coordinator. Therefore, the Reliability Coordinator will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made. 2) "Provisions" allows for multiple solutions – the standard only states what must be done, not how it must be accomplished. No change made.		
Georgia Transmission Corporation	No	(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES. (2) Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.
Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.		

Organization	Yes or No	Question 4 Comment
(2) This requirement codifies the requirement to make available the data necessary to assure reliability and to address specific issues raised in the NOPR. The SDT does not agree that these are administrative requirements. No change made.		
NV Energy MidAmerican Energy	No	In R2 and R3, there is no specificity as to the allowable time for an entity to satisfy a new or modified data supply specification from the RC. As well, there is lack of precision in the use of the term “mutually agreeable” in 3.1 to 3.3. We recommend allowance of a time period, perhaps 90-180 days, for an entity to become fully responsive to requests from the RC for new data or modifications to existing reporting requirements.
Response: No timeframe is specified because each request may involve a different timeframe. The SDT believes that the Reliability Coordinator and the recipient entity will determine a reasonable timeframe on a case-by-case basis. No change made. “Mutually agreeable” allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can’t force a solution on the other entity when that entity may not be physically capable of performing**.** No change made. The SDT believes that it would be self-defeating to specify a specific time period as each situation is different. The requirements as written allow the needed flexibility for this. No change made.		
SERC OC Review Group	Yes	1) The proposed R1.7 in the rationale is not listed in the document. 2) For the entity receiving a data request, it is preferred some language to be added that allows the entity supplying the data to coordinate the request to ensure a sufficient reliability need. Possible language as used in MOD- 001-02, R5 “Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Operator or Transmission Service Provider shall...”

Organization	Yes or No	Question 4 Comment
Response: 1) The rationale box has been corrected to read "Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks." This directly addresses Paragraph 92 of the NOPR. 2) The standard gives the Reliability Coordinator the power to request anything needed for reliability. The Reliability Coordinator is not required to demonstrate the need for this data, as, by definition, the Reliability Coordinator is the function charged with preserving the reliability of the interconnected power system. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Should proposed Requirement 1.2 be included in IRO-010-2 or in a PRC requirement? Southern believes that the SDT should consider if this requirement is better suited for PRC standards. The previous version included Requirement 1.4: "Process for data provision when automated Real-Time system operating data is unavailable." It is unclear why the SDT removed this sub part from the proposed IRO-010. Please provide the SDT's rationale for removing because there are times with the automated methods of providing data are unavailable.
Response: This standard is just a request for data with one 'piece' being Protection System data. It does not deal with the elements or requirements of Protection Systems which are the focus of PRC standards. No change made. This language was deleted because this situation is now covered in approved EOP-008-1, Requirement R1, Part 1.6.2. No change made.		
Peak Reliability	Yes	R1.1: Does "external data" mean one RC has the authority per this Requirement to request data from another RC? R2: The "mutually agreeable" language is potentially problematic, as it is unclear how the RC will receive the data if they cannot reach agreement on the format. Using "a clearly defined format" would be better. IRO-010-1a had a very important statement in R1.4 - "Process for data provision when automated Real-Time system operating data is unavailable." That is important

Organization	Yes or No	Question 4 Comment
		to have a common understanding of expectations and a plan for data delivery even when the automated system is unavailable. This should be added back to the Standard.
Response: R1.1: Yes, it does. R2: Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made IRO-010-1a R1.4: This language was deleted because this situation is now covered in approved EOP-008-1, Requirement R1, Part 1.6.2. No change made.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 - The phrase "as deemed necessary" is ambiguous and leaves the requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state "... including sub-100 kV but greater than 50 kV data". This language is consistent with the NERC BES definition, and has a technical justification developed by that SDT.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Reliability Coordinator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process or that are over 50 KV, it is also true that there may be sub-100 kV points that are not needed as part of the BES or over 50 kV but which the Reliability Coordinator would like to have to flesh out its models. The requirement as written will allow the Reliability Coordinator to obtain this data. No change made.		
American Transmission Company	Yes	R1, R2 - N/A R3 - ATC agrees with the proposed Requirement R3, however, ATC suggests the requirement be reworded as follows to provide clarity and consistency with currently effective Requirement R3 from Reliability Standard IRO-010-1a: "R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission

Organization	Yes or No	Question 4 Comment
		Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications, to the Reliability Coordinator with which it has a reliability relationship, using a mutually agreeable:" 3.1 Format 3.2 Process for resolving data conflicts 3.3 Security protocol"
Response: The SDT does not believe that this suggestion adds clarity. No change made.		
Tri-State Generation and Transmission Association, Inc.	Yes	Tri-State believes R1.1 is written too vague and open ended by stating "as deemed necessary by the RC." Tri-State would like for the team to rewrite that sub-requirement to clarify the intent.
Response: The SDT believes that the Reliability Coordinator is in the best position to determine what data it needs and has written the requirement to allow for that. No change made.		
Salt River Project	Yes	SRP suggests that the RC determines the data obligations listed in R3 Part 3.1, 3.2, and 3.3. The RC is making the request for data so they should provide the format they need the data. Furthermore, if this is determined between each entity and the RC there may be multiple different formats, processes for resolving data conflicts, and security protocols that the RC will need to coordinate. If the RC determines the obligations they would all align.
Response: **"**Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing**.** No changes made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 4 Comment
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered Affiliates	Yes	
Bureau of Reclamation	Yes	
FirstEnergy	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	

Organization	Yes or No	Question 4 Comment
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Response: Thank you for your response.		

5. **Do you agree with the changes made to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has responded to comments requesting clarification and made numerous changes due to industry comments:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact other Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Requirement R1, Part 1.1: Criteria and processes for notifications .

Requirement R1, Part 1.5:

Requirement R1, Part1.6: Provisions for periodic communications to support reliable operations.

R3.

R4:

R5: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

R6: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.

R7: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.

R9: Each Reliability Coordinator shall assist Reliability Coordinators, if requested, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	In Measure M1, for consistency remove the "s" from "notifications" so that the language matches that of R1, or add an "s" to "notification" in R1. To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with the format of other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Requirements R2 and R4, as well as R1 sub-Part 1.1, indicate "and the process to follow in making those notifications." Drafting Teams should focus on developing results-based standards.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. The SDT is striving to develop results-based standards.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc. Florida Municipal Power Agency	No	R1 - Change the word "other" to "adjacent." R1.5 - Similar language was removed from IRO-001-1.1 R3 with the justification "The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act." The same logic should be applied here and this requirement should be deleted. R1.6 - Is the intent for this requirement for adjacent RC's to have a weekly call or that all RC's within the Eastern Interconnection participate in a weekly call? Change R1.6 to state "at least weekly" to synchronize with R4.

Organization	Yes or No	Question 5 Comment
		R2 - Concern with term “Operating Plans” utilized throughout proposed Standards. We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R2.1 - Many of the new requirements imply daily creation of Operating Plans, yet this requirement states annual review. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.2 - Seems to imply that each updated Operating Plan needs written agreement and we don’t believe that adds to reliability. We believe documents should be reviewed and updated as necessary. The way this requirement is written, if any modifications are made to an Operating Plan, a written agreement is needed. We would recommend to remove this requirement since it is strictly an administrative requirement with no reliability benefit. R2.3 - We would recommend to remove this entire requirement since it is strictly an administrative requirement with no reliability benefit. R5 - What is the driver to change from Adverse Reliability Impact to the term Emergency? Seems to move away from focusing on IROL type scenarios. As defined, the term Emergency refers to “any abnormal system condition that requires automatic or immediate manual action...” The use of this term is too broad. We have a concern that too much communication may be required for situations that do not need to be communicated between RCs. We would recommend keeping the term Adverse Reliability Impact. Please provide examples of instances where you would want the RC to RC communication to take place. Also provide examples of what is not considered an Emergency. R5-R9 What situation or need is the SDT trying to fix with these requirements? The term “Emergency” could be pulling in balancing actions instead of reliability needs. These requirements are inter-related and language seems to add confusion. This series of requirements tends to deal with disagreement between RCs and not the

Organization	Yes or No	Question 5 Comment
		focus of developing a coordinated action plan to resolve the Emergency. Language in current standards seems to be a better fit. R6, R8, and R9 seem duplicative. Existing language in IRO-016-1 for communication was more cooperative and the new language is more directive driven. We believe there should be a requirement that the problem is discussed and a coordinated action plan be developed (language in existing IRO-016-1). The term action plan is utilized in R7 which is a good term for Real-time Assessment, but other requirements utilize Operating Plan. R9 - What does implemented its emergency procedures mean? Is this related to the Operating Plan or action plans? It uses the term “requesting entity”...does this refer to a situation when a BA/TOP requests assistance from the RC and their RC requests assistance from another RC? Or does “requesting entity” refer to the requesting RC? It should explicitly state requesting RC if that is what is meant. Why is “emergency” not capitalized in this requirement?
Response: R1: The SDT agrees and has made the suggested change. See summary consideration for revision. R1.5: The SDT agrees and has deleted the requirement. The SDT believes that proposed IRO-001-4, Requirement R1 and the language to ‘act or direct others to act” covers this situation. R1.6: The SDT has deleted Requirement R4 and revised requirement R1, Part 1.6 to address comments. The SDT does not believe that this is an administrative requirement and provides a benefit to reliability. See summary consideration for revision. R2: An Operating Plan is defined as “A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes”. This is the document that will contain the actions necessary to ensure reliability. The SDT believes this is the correct use of the term and that it correctly addresses the reliability need. The SDT does not consider this an administrative requirement. No change made. R2.1: This requirement ensures proper attention is provided to the Operating Plans, Procedures, and Processes. No change made.		

Organization	Yes or No	Question 5 Comment
R2.2: The requirement states that written agreement is required. Any Reliability Coordinator required to take action needs to be aware of the requirement so that it is able to take the prescribed actions and agrees to do so. The SDT believes this needs to be acknowledged in writing and that this is not strictly an administrative requirement. No change made. R2.3: If a Reliability Coordinator is required to take action per an Operating Plan, it needs to be aware of the requirement. Requirement R2 Part2.3 ensures that the Reliability Coordinator knows its responsibilities. The SDT does not consider this a strictly administrative requirement. No change made. R5: The driver to change from Adverse Reliability Impact to Emergency is contained in the rationale. An example of where the SDT could see Reliability Coordinator to Reliability Coordinator communication would be any time it identifies an Emergency. And an example of what is not considered an Emergency is an abnormal situation that does not require automatic or immediate manual action. No change made. R5 – 9: The situation or need addressed by the SDT in Requirements R5 through R9 is the identification of Emergencies and the actions to take should a disagreement arise between Reliability Coordinators. No change made. R6, 8, and 9: Requirements R6 and R8 speak to instances where a disagreement occurs between Reliability Coordinators around the existence of an Emergency. Requirement R9 addresses the need to provide emergency assistance after the requestor has exhausted its remedies. No change made. IRO-016-1: The SDT felt the cooperative dialogue referenced in approved IRO-016-1 would take place during the execution of proposed IRO-014-2 Requirement R5, identifying an expected or actual Emergency and notifying other impacted Reliability Coordinators. If during that notification, disagreement arises, proposed IRO-014-2 Requirements R6 – R8 come into play. No changes made. R7: The action plan in Requirement R7 is for those unique times when a disagreement arises between Reliability Coordinators and a plan needs to be developed to address the situation. No change made. R9: In Requirement R9 the term implemented means the requestor has taken all actions they could and now requires assistance. It does not matter whether it is an Operating Plan or an action plan. The requestor has run out of options and is seeking help. This request is between Reliability Coordinators. To provide greater clarity, the SDT has changed 'entity' to 'Reliability Coordinator'. See summary consideration for revision.		

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	R1 requires RCs to have Operating Plans to inform "... other RC Areas...". Please note that WECC and TRE only have one RC within their Regions (Peak Reliability and ERCOT, respectfully). Where the Eastern Interconnection has 13 RCs, should this type of Requirements be removed and set up similar as IRO-006-EAST-001? This may also be applicable to R9. R1, R2 and R3 an Operating Plan is defined as "A DOCUMENT that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes". There is no reliability benefit to list Operating Procedures or Operating Processes since they are components of an Operating Plan. Recommend "Operating Procedures or Operating Processes" be deleted.
Response: R1: The intent of Requirement R1 is to reinforce coordination between entities. The requirement does just that. Standards are to be written on a continent-wide basis where possible. Neither ERCOT nor Peak Reliability has commented that this requirement doesn't or can't apply to them. No change made. The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	In R4, recommend replacing "other" with "adjacent" and removing part of sentence "within the same interconnection." Current: "Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection." Suggested: "Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with adjacent Reliability Coordinators."
Response: The SDT has deleted Requirement R4 and revised Requirement R1, Part 1.6 to address various comments. See summary consideration for revision.		

Organization	Yes or No	Question 5 Comment
Dominion	No	Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion finds R1.5 to be administrative in nature and therefore do not support inclusion of this sub-requirement. IRO-001-4@R1 already requires the RC to act or direct others to act, to ensure the reliability of its Reliability Coordinator Area. This requirement should be included in whatever authority document the RC provides to its System Operators relative to the function of Reliability Operations and the Functional Entity of Reliability Coordinator (per Functional Model V5). Dominion finds R1.6 to be administrative in nature and therefore do not support inclusion of this sub-requirement. While Dominion agrees that each Reliability Coordinator should be required to participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum requirement. Dominion finds R4 to be administrative in nature and therefore do not support inclusion of this requirement. While Dominion agrees that each Reliability Coordinator should participate in agreed upon conference calls and other forums with adjacent Reliability Coordinators we do not agree with the establishment of a minimum (such as weekly) requirement. We could support if the phrase "at least weekly (per Requirement R1, Part 1.6)" were removed. Dominion does not agree with use of the term Emergency in requirements 5 through 8. Part of the definition of the term includes the phrase "Any abnormal system condition that requires automatic or immediate manual action...". We do not believe that the intent of Standard IRO-016-1@R1 was to wait until immediate action was necessary for the Reliability Coordinator to notify other Reliability Coordinators. We believe the intent was to make notification upon recognition of conditions that indicate a potential, expected, or actual problem. We could support if the words potential or expected were used in conjunction with the term Emergency.

Organization	Yes or No	Question 5 Comment
		Alternatively, we could support language similar to that used in TOP-001-3, Requirement 8.
Response: Periodicity: The SDT believes the commenter is referring to proposed IRO-010-2. Please see response to q4. R1.5: The SDT agrees and has deleted the requirement. R1.6: This is not a new requirement. Approved IRO-014-1, Requirement R1, Part 1.7 currently requires weekly conference calls. The Reliability Coordinators are already doing this and consider it an important concept for reliability. The SDT has revised requirement R1, Part 1.6 to respond to comments. See summary consideration for revision. R4: The SDT has deleted Requirement R4. R5 – R8: The SDT agrees that there should be consistency amongst standards and has changed proposed IRO-014-1, Requirement R5 to agree with the wording in proposed TOP-001-3, Requirement R8. Corresponding changes have been made to proposed IRO-014-2, Requirements R6 through R8. See summary consideration for revisions.		
Duke Energy	No	R1: We suggest changing “may impact other Reliability Coordinator Areas,” to “may impact adjacent Reliability Coordinator Areas.” This revision will reduce ambiguity on the expectations of the RC. Also, we suggest using only the term “Operating Plan” in this standard instead of the use of “Operating Procedures, Operating Processes, and Operating Plans.” We feel that Operating Processes and Operating Procedures are inherent in the definition of Operating Plan, and to list them out in this manner seems to indicate otherwise. R1.5: Similar language was removed from IRO-001-1.1 R3 with the justification “The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act.” The same logic should be applied here and this requirement should be deleted. R2: See comment above regarding the use of the term “Operating Plan.”

Organization	Yes or No	Question 5 Comment
		R3: Duke Energy feels fails to see the differences in the responsibilities of this requirement from those addressed in R2 and R3 of the proposed IRO-010-2. We request that a distinction be made, or suggest the removal of this requirement, as it appears to be duplicative in nature. R4: Duke Energy suggests the removal of this requirement. We feel that a re-wording of R1.6 to the following would satisfy the responsibility, without the necessity of having a specific requirement for participation on conference calls."R1.6: Provisions to schedule and participate in weekly conference calls." R5: Duke Energy is concerned particularly with the use of the terms "Emergency" and "Impacted" in the proposed requirement. The use of the current definition of "Emergency" would result in a substantial amount of notifications to impacted RC(s). An argument could be made, that any action that an RC takes could have a ripple effect that would then prompt notification to impacted RC(s) in an inordinate amount of instances. Also, the term "Impacted" is too broad, and should be more narrowly defined. We suggest reverting back to the old language (Adverse Reliability Impact), as the proposed language does not appear to be selective enough in nature. R6: Duke Energy questions how an auditor is going to measure compliance with the phrase "shall operate as though the problem exits". We suggest reverting back to the currently effective language of "operating to the most limiting parameter" as we feel this language is more effective at resolving possible disputes between RC(s). R7: Duke Energy suggest the following revision: "Each Reliability Coordinator that identified an Emergency shall develop an action plan to resolve the Emergency ." We believe that no matter the circumstances, even if a dispute exists between RC(s), if an RC believes that an Emergency situation exists, the RC identifying the Emergency should be required to develop an action plan to mitigate said Emergency. R8:Duke Energy suggest the following revision: "Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency, unless such actions would violate safety, equipment,

Organization	Yes or No	Question 5 Comment
		regulatory, or statutory requirements." We believe that no matter the circumstances, even if a dispute exists between RC(s), the impacted RC(s) should implement the action plan developed to mitigate the Emergency identified by the identifying RC. R9: We are unclear as to the need for the phrase "provided that the requesting entity has implemented its emergency procedures". A requesting RC may not have an emergency procedure in place to mitigate the issue at the time of the event. We believe the intent of this requirement should be for RC(s) to help one another unless their assistance would violate safety, equipment, regulatory, or statutory requirements. As such, we suggest the following revision: "Each Reliability Coordinator shall assist Reliability Coordinators, if requested, unless such actions would violate safety, equipment, regulatory, or statutory requirements."

Response: R1: The SDT agrees and has replaced "other" with "adjacent". See summary consideration for revision.

The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.

R1.5: The SDT agrees and has deleted the requirement.

The SDT believes that an entity should have the flexibility to use any of the 3 identified documents to fulfill this requirement. No change made.

R3: Proposed IRO-010-2 addresses the collection of data. Proposed IRO-014-3 Requirement R3 speaks to actions spelled out as a result of the collected data integration. No change made.

R4: The SDT has deleted Requirement.

R5: The SDT moved from 'Adverse Reliability Impact' to 'Emergency' for consistency with other similarly worded standards and to bring the requirement to a more inclusive state. Using the term 'impacted' will limit the number of communications required. No change made.

R6: An Auditor will use the suggested evidence outlined in Measure M6 to assess compliance. You may very well operate to the most limiting parameter. What the requirement is saying is that you cannot deny the condition exists and do nothing. The SDT encourages you to submit comments to the posted RSAW to facilitate any changes. No change made.

Organization	Yes or No	Question 5 Comment
R7: Reliability Coordinators develop action plans now for identified Emergencies. This requirement addresses those unique times when not all impacted Reliability Coordinators agree. No change made. R8: The SDT does not believe that the suggested change adds clarity. No change made. R9: The intent of Requirement R9 is to require the requesting Reliability Coordinator to have attempted mitigation, if possible, before asking adjacent Reliability Coordinators to act. No change made.		
SPP Standards Review Group	No	Replace 'the problem' with 'an Emergency' in Requirement R6.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
ACES Standards Collaborators	No	(1) We question the rationale for R6 and ask the SDT to provide examples or guidance in the technical reference guide for scenarios where RCs would disagree whether there is an Emergency or not in an Interconnection.
Response: The rationale for the requirement is that should a disagreement arise, there needs to be a process in place to guide the participants in their ensuing actions. Tie-line loadings are an example of situations where this may arise. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	R2 and 4, as well as the portion of 1.1, which indicates, "and the process to follow in making those notifications" are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
Response: The SDT is striving to develop results-based standards. Requirement R1, Part 1.1 has been revised. The SDT believes there is a reliability-based need for Requirement R2. Requirement R4 has been deleted.		
PNMR	No	IRO-014-1 R3 requires the PC and TP to provide its Planning Assessment to the RC. The rationale states that a summary of the TPL-001-4 assumptions and results would satisfy this requirement. Including this requirement in the IRO is mixing the Operations and Planning Horizons. The drafting team should remove this requirement from IRO-014-1 and recommend that TPL-001-4 R8 be updated to include the RC.

Organization	Yes or No	Question 5 Comment
Response: The SDT believes this comment refers to proposed IRO-017-1. Please see responses to q6.		
David Kiguel	No	R9: How will the RC that requested assistance demonstrate and how will the RC whose assistance was requested verify that the requesting entity has implemented its emergency procedures?
Response: The SDT believes that a Reliability Coordinator will not ask for assistance without having first instituted its own procedures. Normally, agreements are already in place to cover this situation. Things can, and will, be sorted out after the fact as to whether the proper protocols have been followed.		
Electric Reliability Council of Texas, Inc.	No	R3 and R5 appear to be redundant. R5 would be under the notifications identified in R3. If the SDT does not believe R1 is explicit enough to identify emergencies under R1.1, then clarify R1 so that R5 can be deleted. While other requirements use the term “impacted” to limit Emergency to just those that raise to the level of needing coordination with other RCs, R7 is silent and although infers, if read solitarily, could create the issue of interpreting all “Emergencies” which is not the intent. ERCOT suggests including language that limits R7 scope to only those Emergencies that rise to the level of needing coordination with other RCs, since the SDT has chosen to replace Adverse Reliability Impact with Emergency as that term includes local Emergencies as well. R9 (and TOP-001-R7) make sense from the context of having additional circumstances arise in real time that were not “planned” actions. It allows for assistance outside of agreed upon and coordinated plans to take place. This is accurate in that you cannot plan for every type of occurrence that is possible. If this is the context that the SDT imagined, ERCOT recommends capturing such concept within the RSAW. If it is not, ERCOT recommends deleting both requirements as it is redundant to the requirements requiring actions per plans to be taken. It would be beneficial to see the auditor’s approach to expectations associated with RCs that are in separate Interconnections connected via DC Ties in the RSAW for IRO-

Organization	Yes or No	Question 5 Comment
		014. DC Ties are viewed as resources or loads within the ERCOT Interconnection. While R4 is clear on the issue, the other requirements are vague.
Response: The SDT has deleted Requirement R3. The SDT agrees and has made the suggested change. See summary consideration for revision. R9 and DC ties: The RSAWs for this project have been posted and are available for comment.		
Texas Reliability Entity	No	1) R1: Use of the word "Provisions" in 1.6 is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a conference bridge) for conduct weekly conference calls? Or is it meant that the RC shall identify how the calls will be scheduled and conducted? If the latter, the word "provisions" should be replaced by "specifications". 2) R4: R4 seems to contradict R1. R1 requires each RC to have Operating Procedures, Processes or Plans for actions that may impact other RC areas; including provisions for weekly conference calls. R4 limits the requirement for RCs to participate in weekly conference calls to other RCs within the same Interconnection. Is it the SDT intent to have RCs have weekly conference calls with other RCs in the same Interconnection only? We recognize this may not be an issue outside of the ERCOT region, but we seek clarification from the SDT. 3) R's 6, 7 and 8: Requirements 6, 7 and 8 seem to exclude the situation where RCs agree. All the same actions should be taken for 6, 7 and 8 regardless of whether RCs agree or disagree on the existence of an Emergency. 4) R8: The purpose of the standard is to preserve the reliability benefits of interconnected operations. As such, for R8, each RC's implementation of another RC's action plan should have a required time frame. In addition, if the RC does not implement the action because such actions violate safety, equipment, regulatory or statutory requirements they should be required to notify the RC who developed the action plan within a required time frame.

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Requirement R1 Part 1.6 for clarity. See summary consideration for revision. 2) The SDT has deleted Requirement R4 and revised Requirement R1, Part 1.6 in response to this comment and those of others. See summary consideration for revisions. 3) The SDT believes that Requirement R5 addresses the situation in question since the entity must declare the Emergency in order to move on to Requirements R6 to R8. No change made. 4) The SDT believes that the Reliability Coordinator developing the plan will include a timeframe for implementation in the plan. No change made.		
Arizona Public Service Company	Yes	IRO-014 R9: There are one too many "be"s, "cannot be physically be implemented"
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
Peak Reliability	Yes	R1.6: "Provisions for weekly conference calls" should be "Provisions for weekly conference calls with Reliability Coordinators within the same Interconnection" to match the language of R4. R2: The current Standard allows for 36 months. It is unclear why this changed. There doesn't seem to be a reliability issue that would precipitate this change. Also, R2.2 should be changed to language consistent with EOP-006-2 R2 & R4. R5 & R7: "Each Reliability Coordinator that identified an Emergency" should be changed to "Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area" If one RC identifies and Emergency in another RC's Area, and there is disagreement, the first RC should not be required to develop a plan. R9: "unless such actions cannot be physically be implemented or would violate safety, equipment, regulatory, or statutory requirements" should be changed to "unless such actions would cause adverse reliability impacts or would violate safety, equipment, regulatory, or statutory requirements".

Organization	Yes or No	Question 5 Comment
Response: The SDT has revised Requirement R1 Part 1.6. See summary consideration for revision. R2: The SDT believes that such an important concept requires annual review. No change made. R2.2: The SDT believes that while the words are not exactly the same that the bottom line will be the same and that the suggested change therefore, adds no additional clarity. A written agreement implies a review No change made. R5/R7: The SDT believes that it is implicit in the requirements (and the Functional Model) that a Reliability Coordinator can only declare an Emergency in its own Reliability Coordinator Area and that the suggestion is basically redundant. However, to improve clarity, the SDT has made the suggested change. See summary consideration for revision. R9: The SDT disagrees. The indicated language was in proposed IRO-014-2 which was Board-approved but is proposed for rejection in the FERC NOPR. The current language is consistent with other proposed requirements in this project. No change made.		
Colorado Springs Utilities	Yes	No Comments
PacifiCorp	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PPL NERC Registered Affiliates	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
ReliabilityFirst	Yes	
PJM Interconnection	Yes	
Consumers Energy	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	
Salt River Project	Yes	
NV Energy	Yes	Most of these requirements are predicated on the idea that multiple RC entities exist within a particular Interconnection. Accordingly, most of the requirements will be inapplicable to the WECC and TRE areas.
MidAmerican Energy	Yes	
Response: Thank you for your response.		

6. **Do you agree with the changes made to proposed IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration:

The SDT has made the following changes due to industry comments:

Purpose: To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.

R1, Part 1.1.2: Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s) .

R1, Part 1.3: Define the process to evaluate the impact of Transmission and generator outages within its Wide Area.

R1, Part 1.5:

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	The Purpose needs to be revised to indicate that the outages are properly coordinated between whom? To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
Response: The SDT agrees and has revised the Purpose statement accordingly. See summary consideration for revisions.		

Organization	Yes or No	Question 6 Comment
Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1.3 and R1.5 seem to be stating the same thing just using different language. Please clarify the difference between the 2 requirements. R1.1.2 - Recommend to delete the language “prior to submitting to RCs”. Each RC should be able to define their process to fit their area. M2 - Could an attestation from the RC that each TOP and BA followed the outage coordination process be evidence? A concern on what the evidence would look like if this was not feasible. R3 & R4 - The PC’s and TP’s planning horizon is Year One and beyond. They do not cover the Operations Planning time horizon, so how do R3 and R4 practically apply to the RC. The PC’s and TP’s have the responsibility to develop “corrective action plans” for identified issues or conflicts for the time frame they are studying. Recommend to strike R3 and R4 from this standard. If keeping R3, then it should be in the TPL standard, not the IRO standard.
Response: The SDT agrees and has deleted Requirement R1, Part 1.5. The SDT agrees has deleted “prior to submitting to Reliability Coordinators” from Requirement R1, Part 1.1.2 as suggested since the process document can be tailored in this fashion if desired by the Reliability Coordinator. See summary consideration for revisions. The SDT believes that the evidence list in measure M2 is not intended to be exhaustive and already contains provision for other evidence types by virtue of the “could include, but is not limited to” clause. The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations. While the SDT agrees that R3 and R4 could be incorporated into a future version of TPL-001, the SDT believes that, due to timing, the requirements should be kept in IRO-017 until such a change occurs.		

Organization	Yes or No	Question 6 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing Georgia System Operations Georgia Transmission Corporation	No	Overall, Southern does not agree with this new outage coordination standard. This standard is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary, which is current day and next day operations. As written, this requirement conflicts with the Functional Model and the NERC Glossary, which both clearly address the roles of the Reliability Coordinator. The Reliability Coordinator, according to the Functional Model, "receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis." Furthermore, the NERC Glossary notes that the Reliability Coordinator "is to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations." This definition indicates that the Reliability Coordinator's scope is for next day and real-time operations. Southern recommends that this standard be withdrawn from the project. If the SDT does not withdraw the standard, at a minimum, the SDT should modify the standard to address the following comments. The proposed subpart 1.5 requires RCs to document and maintain the specifications for outage analysis during the operations planning horizon, which is next day to one year out. We do recognize that the SDT's rationale provides the RCs with some discretion as to whether or not the RC desires to have specifications for outage analysis in the operations planning horizon; however Southern recommends adding language to subpart 1.5 to clearly state that the RC has discretion by adding ", if deemed necessary by the RC" to the end. Southern does not agree with R4 as it seems to imply that RCs conduct outage coordination assessments even beyond the operations planning horizon. Again, RCs are focused on real time and next day timeframes, not the Planning Assessment timeframe, and should not be required to coordinate solutions in the Planning Assessment timeframe. This requirement is expanding the responsibilities of the RC beyond that contemplated in the NERC Functional Model and NERC Glossary (see definition of RC), which is current day and next day operations. This requirement

Organization	Yes or No	Question 6 Comment
		should be removed, or, at a minimum, be revised to include “if deemed necessary by the RC”. The existing TOP-002-2.1b R11 requires TOPs to perform seasonal studies to determine SOLs and to provide the results of those studies to its RC.
Response: The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations. The SDT agrees and has deleted Requirement R1, Part 1.5. The SDT notes that approved TOP-002-2.1b, Requirement R11 is proposed for retirement. The SDT believes that no new reliability gaps are being created by this retirement due to new requirements included in proposed IRO-017-1, when coupled with requirements in approved FAC-014-2 Requirement R2 (determination of SOLs), proposed IRO-008-2/TOP-002-4 revisions (identifying SOL and IROL exceedances), approved MOD-001-2 Requirement R1 (TTC determination), and proposed IRO-017-1 (requiring joint development of solutions in the Near-term Transmission Planning Horizon, and strengthened coordination processes within the operations planning time horizon).		
Dominion	No	Dominion does not believe that sub-requirement 1.5 allows the Reliability Coordinator to request seasonal planning assessments if so desired. Instead it appears to require they do so. We suggest revising to read “Document and maintain the specifications for outage analysis during the operations planning horizon if desired.”
Response: The SDT proposes to delete Requirement R1, Part 1.5 based on comments indicating duplicity with Requirement R1, Part 1.3, so the suggested edits are unnecessary.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes seasonal analyses to evaluate planned maintenance is an important reliability function that should not be lost and cannot be replaced by

Organization	Yes or No	Question 6 Comment
		"Planning Assessments". Recommend modifying R1.5 as follows: "Specify a periodicity, not less frequently than seasonally, of outage analyses during the operations planning horizon."
Response: See response to FRCC comments. While the SDT proposes to delete Requirement R1, Part 1.5, it is certainly permissible for a Reliability Coordinator to include seasonal assessments as part of its outage coordination process document, if it deems necessary.		
Duke Energy	No	R1: Duke Energy believes using the Operational Planning Horizon expands the RCs responsibility beyond next day operations and does not align with the responsibilities of an RC as defined in the NERC Functional Model. R1.1.2: Duke Energy suggests the following revision: "Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s)."Each RC should be able to define their process for submitting outage coordination data to fit their RC Area. R1.3/ R1.5: Duke Energy believes these two sub-requires are duplicative and suggests the removal of one of them. Please clarify the difference between the 2 sub-requirements. M2: Duke Energy suggests adding a provision that an attestation from the RC stating that their BA/TOP followed their RC Outage Coordination Process is acceptable evidence. R3/R4: Duke Energy recommends the removal of R3 and R4. The TPL Planning Assessments are not used in the Operations Planning horizon. Additionally, we fail to see the reliability based need for an RC to have the kind of analysis provided by a Transmission Planner/Planning Coordinator. The assessments made by a TP/PC are in located in the time horizon of 1-year and beyond, with some assessments potentially being as far as 20-years into the future. With the RC's

Organization	Yes or No	Question 6 Comment
		responsibility mainly focused on Real-time operations, we do not agree that providing the planning assessments alluded to in R3 and R4 is necessary.
Response: The SDT believes that the Reliability Coordinator involvement in coordination of future outages beyond the next-day horizon is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT also believes that the functional model should be revised in the future reflect this need. The SDT agrees and has deleted “prior to submitting to Reliability Coordinators” from Requirement R1, Part 1.1.2. The process document can be tailored as suggested if desired by the Reliability Coordinator. See summary consideration for revisions. The SDT agrees with the comment regarding overlap between Requirement R1, Parts 1.3 and 1.5, and proposes to delete Requirement R1, Part 1.5. The SDT believes that the evidence list in Measure M2 is not intended to be exhaustive and already contains provision for other evidence types by virtue of the “could include, but is not limited to” clause. No change made. The SDT is responding to issues raised in the FERC NOPR and in the IERP Report to expand the scope of outage planning to incorporate Reliability Coordinators into this planning process. However, the SDT agrees that the primary responsibility in the Near-term Transmission Planning Horizon is on Transmission Planners and Planning Coordinators, and has updated R4 as noted in the summary considerations.		
Bureau of Reclamation	No	Reclamation believes that Generator Operators should be included in the proposed outage coordination standard. Like TOP-003-1, IRO-017-1 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. The standard should acknowledge that generators may have unplanned outages due to safety concerns, equipment concerns, regulatory requirements, or statutory requirements.
Response: The SDT believes that Generator Operator data on planned outages will be incorporated into the process through the Balancing Authority. No change made.		
BC Hydro and Power Authority	No	The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP’s and BA’s follow. The responsibility for

Organization	Yes or No	Question 6 Comment
		coordination should reside with the TOP's and BA's, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA's responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage analysis. An RC driven coordination process does not account for differences and needs of TOP's and BA's, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA's, responsibility for assessment of system wide conflicts

Organization	Yes or No	Question 6 Comment
		through study assessment, and development of conflict resolution processes to support operations.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report, although this does not diminish the role of Transmission Operators and Balancing Authorities in that effort. The SDT suggests that the commenter review the mapping document to see how the cited requirements are being handle moving forward. No change made.		
SPP Standards Review Group INDN - Independence Power & Light	No	The recent trend at NERC is to eliminate subparts. Therefore, change the formatting on Requirement 1 Subparts 1.1.1 and 1.1.2 to bullets. We recommend that Requirement R3 be deleted in that it is redundant with TPL-001-4, Requirement R8. If the Reliability Coordinator has a need for the assessment, the Reliability Coordinator can request a copy of the assessment from the Planning Coordinator and Transmission Planner who are then obligated to provide a copy of the assessment to the Reliability Coordinator.
Response: The SDT does not agree that it is necessary to eliminate sub-parts and that the use of sub-parts here is appropriate. The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated Requirement R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		
ACES Standards Collaborators	No	(1) Requirement R2 needs to be clarified, as it leaves too much room for interpretation from auditors. What does “follow” mean? Does this mean to follow Operating Instructions? If so, then it would be redundant with IRO-001. If “follow”

Organization	Yes or No	Question 6 Comment
		means to have a copy of the RC outage coordination process, then it meets Paragraph 81 criteria as an administrative task. We recommend striking requirement as there are other methods for the RC to ensure that the TOP and BA will “follow” the RC instructions for outage coordination.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
ISO/RTO Standards Review Committee (SRC)	No	R2 VRFs should be Medium, not Low. (note: CAISO does not agree with this comment). Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it’s the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC:- Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.
Response: With no justification provided for the suggested change to the VRFs, the SDT is unable to respond to this request. The VRF/VSL Justification Document provides the reasoning for the SDT assignment of a Low VRF. No change made. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. In addition, the data from the Generator Owners and Transmission Owners will be forwarded by the Balancing Authorities and Transmission Operators respectively. Specifics of the coordination mechanisms, which may vary depending on entity structure, can be detailed in the outage coordination process documents mandated by Requirement R1. No change made.		

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	Since this Standard only includes the operations planning horizon, BPA does not feel it is necessary or appropriate to include Planning Coordinator (PC) and Transmission Planner (TP) as applicable functions. BPA believes requirements R3 and R4 should be applicable to Transmission Operators (TOPs), but not TPs or PCs. BPA also feels that identifying Planning Assessment in this Standard creates a conflict by introducing the Planning Horizon into a Standard that should only cover an operations horizon. The Planning Assessments in TPL-001-4 are not the type of seasonal or outage planning assessments performed by TOPs. The TP would not be assessing planned outages in the Planning Assessment.
Response: The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that any coordination of a Planning Assessment between appropriate entities is covered in TPL-001-4 R2, R3, and R8. Furthermore, CenterPoint Energy feels the Reliability Coordinator is a Real-Time function per the NERC Functional Model and should not have a compliance responsibility in coordination of a Planning Assessment between the Planning Coordinator and Transmission Planner. CenterPoint energy recommends removing IRO-17-1 R3 and R4.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT believes that Requirements R3 and R4, which go beyond the scope of the approved TPL-001-4, could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		

Organization	Yes or No	Question 6 Comment
CPS Energy	No	"Transmission Planner" should be stricken from requirement R3, as the Transmission Planner is already obligated to provide the Planning Assessment to the Planning Coordinator through TPL-001-4. The requirement R4 should be stricken entirely, since this study is already performed and reported in the Planning Assessment required by TPL-001-4.
Response: The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		
Ingleside Cogeneration LP	No	ICLP believes that this is a perfect example of a standard that should inherently assume that a mostly automated process exists. Most outage coordination already takes place through ISO-managed portals because of the convenience, data consistency, and security they provide. Instead of playing to the least-common denominator (i.e.; fully manual outage coordination), IRO-017-1 should be written in a manner that assumes that portals exist - rendering most of the requirements in this standard irrelevant.
Response: The SDT believes that it is tasked to specify requirements, not how an entity would comply with such requirements. While such portals may exist in many areas, it is not necessary to have such technological capabilities to achieve the reliability objectives of the requirement. No change made.		
American Transmission Company	No	ATC requests that the SDT consider making the following modifications: a. R1 - N/A b. R2 - ATC agrees with the proposed IRO-017-1 Requirement R2. c. R3 - To provide more specificity and flexibility, ATC suggests Requirement R3 be reworded as: "R3. Each Planning Coordinator and Transmission Planner shall make each new Planning Assessment available to impacted Reliability Coordinators and their Transmission Operator(s)." The revised language clearly indicates which Planning Assessment is provided and when. In addition, the language allows PCs and TPs to make a web-based version of the Planning Assessment and not require

Organization	Yes or No	Question 6 Comment
		conversion of the Assessment to a form that can be transmitted to applicable Reliability Coordinators by mail or email. Finally, ATC suggests that Transmission Operators be added as an applicable entity for receipt of the Assessment. d. R4 -ATC suggests removal of the proposed Requirement R4 entirely. The rationale is that the Reliability Coordinator should not have to resolve potential planned outage conflicts more than one year out with the Planning Coordinator and Transmission Planner. There are too many variables on this time scale that affect the answer. A better approach would be for the RC, TOP(s) and GOP(s) to resolve any outage conflicts, including moving or cancelling the outage, once the time window is within the "one year out" timeframe.
Response: (a. and b.) Thank you for your support. c. The SDT does not believe that the suggested change adds any clarity. And the SDT does not believe that the Transmission Operator should be included in the requirement. The desired coordination is between the Reliability Coordinator, Planning Coordinator, and Transmission Planner and does not need to include Transmission Operators. No change made. d. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. No change made. e. The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. The SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in R4 to clarify applicable entities, as noted in the summary comments. The SDT agrees that Requirements R3 and R4, which go beyond the scope of the approved TPL-001-4, could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		

Organization	Yes or No	Question 6 Comment
Austin Energy	No	: City of Austin dba Austin Energy (AE) supports the separation of the Outage Coordination standard, though we believe it is not entirely necessary. R1 and R2 could be easily included in one of the other standards (where they were originally). AE believes R3 and R4 are unnecessary in their entirety and asks the SDT to remove them. AE does not understand the purpose they are trying to fulfill, as there is no mention of them in the mapping document. Further, AE believes R3 and R4 are redundant with requirements in TPL-001-4, which becomes enforceable on 1/1/15. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. Alternatively, IRO-017-1, R4 can be subsumed into IRO-017-1, R1, as any outage coordination should take place through the Transmission Operator. The RC can develop its R1 process to require the submittal of longer-term outages, if necessary, and outage conflicts would then be covered and resolved through R1 Part 1.4.
Response: The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		
Liberty Electric Power, LLC	No	There is no language regarding which entities the plan will be "made available" to. Generators should be included on the list so they can plan outages knowing the process being used to approve or deny requests.

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	No	Requirement R1 requires the Reliability Coordinator to identify the roles and develop a process for coordinating outage plans between TOPs and BAs. However, the BA does not develop generator outage plans or schedules; it's the GO that develops generator outage plans and submit to the BA for assessing resource-demand-interchange balance. Further, as indicated in the Functional Model, the RC:- Receives transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis. - Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability. We suggest the SDT consult the FMWG on the appropriate functional entities that should be responsible for coordinating outage plans, and revise R1 (and R2) accordingly.
Response: The SDT envisions that these details would be elaborated in the process document. No changes made.		
Oncor Electric Delivery LLC	No	Proposed Standard IRO-017-1 R3 states: "Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators." Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
Response: The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated Requirement R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document.		

Organization	Yes or No	Question 6 Comment
Hydro One	No	We believe that IRO 017 -1 needs more work. From an Ontario perspective the TP and PC do not coordinate outages.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. However, the SDT has modified Requirement R4 to clarify roles, as noted in the summary comments		
Lincoln Electric System	No	To avoid requiring the distribution of the Planning Assessment within separate standards, LES recommends that requirement IRO-017-1 R3 be removed altogether. TPL-001-4 R8 already allows for “any entity that has a reliability related need” to submit a request for the Planning Assessment. Dividing what is essentially the same requirement between two separate standards introduces unnecessary compliance risk for registered entities. If the drafting team believes the RC should be identified as a recipient, then TPL-001-4 should be revised to reflect this change. As currently drafted, R4 would require the Planning Coordinator and Transmission Planner to coordinate solutions with the RC for issues identified during planned outages in the Planning Assessment which can extend into the Planning Horizon. To ensure the correct timeframe is reflected in the standard, LES recommends revising R4 to specify that the PC/TP/RC should only coordinate solutions in the Operations Planning Horizon (Operations planning horizon is next-day to one year out), and not outside the Operations Planning Horizon into the Planning Horizon. The RC should coordinate solutions within the RC area.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. Approved TPL-001-4, Requirement R8 does not include the Reliability Coordinator. However, the SDT has corrected the Time Horizon to include Long-term Planning to better reflect the intent of the standard. This will correctly incorporate Planning Coordinators and Transmission Planners. The SDT has also modified the language in Requirement R4 to clarify applicable entities, as noted in the summary comments.		

Organization	Yes or No	Question 6 Comment
Electric Reliability Council of Texas, Inc.	No	ERCOT believes "develop" in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 "document and" with "maintain", which is sufficient. Document is purely administrative. M1 infers a requirement by including "dated". By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. R3 should be incorporated into TPL-001-4 R8 if it is necessary. R4 is vague and may be duplicative with TPL-001-4 R2.7 which requires development of a Corrective Action Plan whenever system performance (with known outages modeled) doesn't meet Table 1 requirements. R1.5 should address evaluation of outages in an operations planning timeframe. If more specificity is needed to address within XX amount of days in advance, that should be clarified.
Response: The SDT believes that the terminology in the requirement is correct as written. Develop is a necessary part of the equation. No change made. The SDT proposes to delete Requirement R1, Part 1.5 based on comments indicating duplicity with Requirement R1, Part 1.3, so the suggested edits are unnecessary. The SDT believes that proposed IRO-017-1 goes beyond approved TPL-001-4. Approved TPL-001-4, Requirement R8 does not explicitly cite the Reliability Coordinator as a receiving entity but would necessitate that the Reliability Coordinator submit a written request for the Planning Assessment. Proposed IRO-017-1, Requirement R3 makes it mandatory to include the Reliability Coordinator. Further proposed IRO-017-1 Requirement R4 necessitates Reliability Coordinator involvement in identifying solutions to identified issues. However, the SDT has updated R4 as noted in the summary considerations. The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement		

Organization	Yes or No	Question 6 Comment
R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document. Incorporation of 'dated' in measures is an accepted concept. No change made.		
Salt River Project	No	Per R1, the RC must develop an Outage Coordination process that will take many aspects out of the BA & TOPs hands, specifically flexibility for units or crews on their start and end times. This decreased flexibility can lead to increased costs. R3 is burdensome to provide textual summaries of load flow studies and the assessment information for those studies. There are also concerns over distributing assessment information externally. R4 requires the Transmission Planner to coordinate solutions for issues or conflicts with planned outages. Outage coordination can be managed by Transmission Operators. SRP suggests allowing for Transmission Operators to coordinate solutions with the RC and PC.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages beyond the next-day horizon is necessary to respond to issues raised in the FERC NOPR and in the IERP Report, although this does not diminish the role of Transmission Operators and Balancing Authorities in that effort. No change made. Requirement R3 requires the distribution of the Planning Assessment which is typically a text document with summaries of load flow studies and thus shouldn't be burdensome. No change made. The SDT does not believe that the Transmission Operator should be included in the requirement. The desired coordination is between the Reliability Coordinator, Planning Coordinator, and Transmission Planner and does not need to include Transmission Operators. No change made.		
NV Energy MidAmerican Energy	No	R3 and R4: The Planning Assessment is being introduced as a coordination tool for communication to the RC in R3, and coordination actions pursuant to the Assessment are specified in R4. Given that the RC operates in the Operations Planning and Real-Time environment, yet the Planning Assessment is a long term planning instrument, we do not believe that this coordination is applicable or useful. Rather, the RC should

Organization	Yes or No	Question 6 Comment
		be seeking next-day assessments from the TOP entities within its footprint. Suggest removal of these requirements.
Response: The SDT believes that Reliability Coordinator involvement in coordination of future outages is necessary to respond to issues raised in the FERC NOPR and in the IERP Report. However, changes were made to Requirement R4 as noted in the summary comments, to further clarify the intent of this requirement.		
Peak Reliability	Yes	o R1.3: “Reliability Coordinator Wide Area” should be “Reliability Coordinator’s Wide Area”
Response: The SDT agrees and has changed the requirement to “its Wide Area” for clarity. See summary consideration for revisions.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R4 - The term “coordinate” is ambiguous and unclear and may lead to unintended compliance implications. For example, is coordination satisfied by notice? RF recommends replacing the term “coordinate” with “jointly develop” in order to avoid unintended confusion.
Response: The SDT agrees and has made the suggested change. See summary consideration for revisions.		
Idaho Power	Yes	I don’t have any great concerns with IRO-017-1 but R1 seems a little vague. Depending on the process that the RC establishes this could become quite onerous, it would be better if more of the outage coordination process was defined in the standard itself rather than leaving it entirely up to the RC.
Response: The SDT’s intention was to permit a variety of coordination processes to better fit the individual needs of different Reliability Coordinators. No change made.		
Texas Reliability Entity	Yes	1) R 1.3: "Reliability Coordinator Wide Area" is not a defined term. Recommend removing the word "Wide" and use the defined term of Reliability Coordinator Area.

Organization	Yes or No	Question 6 Comment
Response: The SDT has clarified Requirement R1.3 to "its Wide Area". Please refer to the summary of changes.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	No Comments
SERC OC Review Group	Yes	
PPL NERC Registered Affiliates	Yes	
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	

Organization	Yes or No	Question 6 Comment
Xcel Energy	Yes	
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Ameren	Yes	
Consumers Energy	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Response: Thank you for your response.		

7. **Do you agree with the changes made to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes**

Summary Consideration: There were a great deal of comments on proposed TOP-001-3 the majority of which were seeking clarifications, consistency, or relatively slight changes to requirements to make them more equitable. The SDT has responded to all comments and has made the following changes due to industry comments:

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

R1. Each Transmission Operator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area.

R2. Each Balancing Authority shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator

M4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued . If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to identify any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Data retention: Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.

R18. Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs.

Data retention: Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, and R14 through R20 and Measure M1 through M11, and M14 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Requirement R5 has a zero-defect problem similar to what was argued for COM-002-4. A single instance of a failure to comply with any Operating Instruction results in a severe violation. We recommend a revision to this approach more consistent with the COM-002-4 penalties. A demonstrated pattern of problems would trigger a Severe VSL, but isolated single events, which did not impact the BES, should not be penalized. (It is hard to argue that not following an OI when one can during an Emergency would not be a severe VSL. Graduated levels could be similar to COM-002-4 R5.) FERC has stated that VSLs should be graded. These are not. Further, intent to perform should count in favor of any entity that is unable to implement an Operating Instruction due to a technical or reliability related concerns. (It is hard to argue that not following an OI when one can during an Emergency would not be Severe. Graduated levels could be similar to COM-002-4 R5.) Regarding Requirement R13, TOPs perform Real-time Reliability Assessments using their EMS Contingency Analysis systems and it is reasonable to expect that such systems would generate results at least every 30 minutes. However, a failure of the EMS or SCADA or of the contingency analysis software should not automatically result in a severe violation. For example, EOP-008-1 R1 allows a TOP two hours following the loss of primary control center functionality to re-establish situational awareness, yet such an event would automatically result in a severe violation of this requirement. We suggest revising R13 to read: Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. There is no way to perform a Real - time Assessment without EMS and SCADA given the new definition. In Measure M4, change Generation Operation to Generator Operator. In Measure M5, suggest changing "...Operating Instruction issued by the Transmission Operator(s)" to "...Operating Instructions issued by the Balancing Authority" to match the language in R5.

Organization	Yes or No	Question 7 Comment
		In Measure M6, suggest changing "Balancing Authority" to "Transmission Operator" in the last sentence of the paragraph "If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation." to match the language in R6. Regarding Measure M8, no evidence is needed to show that the Transmission Operator informed the impacted Balancing Authorities. If so, why are they included in R8? Throughout the standard we find "an SOL". In the IRO standards we see "a SOL". Should be “a SOL”. To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. Requirements R1 and R2 appear to create a double jeopardy situation as the TOP is already obligated to comply with all the other requirements for which it is the functional entity. To do so might necessitate issuing Operating Instructions to direct others to act. For example: A TOP needs to issue an Operating Instruction to shed load to comply with EOP. If the TOP does not issue the OI then it won’t comply with its EOP load shed plan. That is a failure to shed load and failure to issue the OI. It is important to clarify R7 by retaining the concept of comparability of actions. For example, the requested TOP or BA should not be expected to implement load shedding if the requesting TOP hasn’t exhausted that option. Suggest changing emergency procedures to comparable emergency procedures. In R8 we agree the TO should inform impacted entities of operations that result in an emergency. However, including operations that “could result in an emergency” is far too broad and might potentially result in limitless notifications. R9 has several issues that need to be addressed. The SDT is utilizing the word negative to limit the need to make notifications, but it is introducing ambiguities in the meaning and determination of negative impact that could result in an unbounded

Organization	Yes or No	Question 7 Comment
		requirement to make notifications. We suggest introducing additional phrases to define negative. Negative impact should mean to reduce the ability to perform an entity's reliability function. The Measure states this is limited to planned outages while the requirement does not use the word planned. This needs to be resolved. The requirement to coordinate outages would conflict with and cause double jeopardy with the existing COM-001 R3 requirement to coordinate telecom systems within and between areas, including investigating and recommending solutions to problems. It also conflicts with proposed COM-001-2 R10 to within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. The Southwest Outage Report was specific about loss of RTCA. As written the requirement could be interpreted to mean recording loss of a control point or analog value and whether it impacted another NERC entity, and evidence of notification. Consider revising R9 to read: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that utilize the outages equipment in the performance of their reliability functions of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. A different approach would be to split the requirements into a BA and a TOP limited Requirement. The BA would remain the same as the suggested rephrasing above and the TOP would state: Each Transmission Operator shall notify its Reliability Coordinator and those interconnected NERC registered entities that are within the TOP Area that the TOP Real-time Contingency Analysis tools are not functioning properly and reduces the ability of the TOP to monitor its area. Regarding R10, if a sub-100 kV facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor

Organization	Yes or No	Question 7 Comment
		BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP's entire area when in reality a subset of facilities may be all that is required. One suggestion rephrasing is Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area... Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. Requirement R16 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R17 could be clarified by using the wording in IRO-002-2 R8, which is the same requirement for the RC. Requirement R16 and R17--System Operators should have authority to both approve and disapprove planned outages and maintenance of its monitoring and Real-time assessment (analysis) capabilities. "...maintenance of its monitoring and analysis capabilities." What is "its" referring to? The Rationale isn't clear on this either.

Response: Please see response to q14.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

Organization	Yes or No	Question 7 Comment

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.

The SDT has deleted 'telecommunications' from the requirement as it is already covered in proposed COM-001-2 Requirement R3. See summary consideration for revision.

The SDT agrees with changing Generation Operator to Generator Operator in Measure M4. See summary consideration for revision.

The SDT agrees with changing Transmission Operator to Balancing Authority in Measure M5. See summary consideration for revision.

The SDT agrees with changing Balancing Authority to Transmission Operator in Measure M6. See summary consideration for revision.

The SDT modified Measure M8 to include Balancing Authority in the measure. See summary consideration for revision.

The SDT agrees that "an SOL" is grammatically incorrect and has changed to "a SOL" throughout the standards.

Organization	Yes or No	Question 7 Comment

Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.

The requirement already includes the requesting entity to have "implemented its emergency procedures". Thus, the "concept of comparability of actions" is already included. No change made.

The SDT disagrees that "including operations that 'could result in an emergency' is far too broad". The Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators need to be aware of the threats to the reliability of the Bulk Electric System including potential threats. The SDT does not believe that this will result in "limitless notifications". No change made.

The SDT agrees that using "negative" in Requirement R9 creates ambiguity. Requirement R9 has been modified to remove the term "negative" as well as to accommodate other changes suggested by industry. See summary consideration for revision.

The SDT agrees that Requirement R9 and Measure M9 need to be consistent with regard to inclusion of all telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Measure M9 has been modified to remove the word "planned". See summary consideration for revision.

The SDT disagrees that Requirement R9 conflicts with COM-001.1 Requirement R3. Requirement R9 does not require coordination but rather only notification. Furthermore, proposed COM-001-2 has been approved by the NERC Board and is pending regulatory approval before the Commission. Thus, approved COM-001.1 Requirement R3 is expected to be retired. The SDT has made clarifying changes to Requirement R9 based on comments received. See summary consideration for revision.

While the SDT recognizes that Requirement R9 may be liberally interpreted as applying to a single control point that was not the intent of the requirement and believes a reasonable reading of the requirement would be that it applies to only the equipment that impacts other entities. Thus, most control points or analog values will not have an impact and will not be covered. However, there may be certain important control points or analog values (e.g., IROL flow or tie-line flow) that do impact and are covered. The proposed changes are more confusing and ambiguous. Furthermore, the SDT disagrees with splitting the requirement into Transmission Operator and Balancing Authority requirements as proposed. The purpose of the requirement is not just for the Transmission Operator to notify other entities when its RTCA is not functioning but to notify other entities of outages such as telemetry outages that could affect their monitoring tools. The SDT has made clarifying changes to Requirement R9 based on comments. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
For Requirement R10, the SDT agrees that if a sub-100 kV facility is needed to maintain reliability that it should be included in the BES by exception. Thus, the SDT has modified the requirement accordingly. The SDT agrees that the requirement could imply the need for a Transmission Operator to monitor all of its neighboring Transmission Operators Facilities and that the Transmission Operator only needs to monitor its neighbor's Facilities that would impact its reliability. The requirement has been modified accordingly. See summary consideration for revision. The SDT agrees and has changed proposed TOP-001-3, Requirements R16 and R17 to match proposed IRO-002-2, Requirement R3. See summary consideration for revision. The SDT disagrees. Authority to approve provides de facto authority to not approve. No change made. "its" is used to imply ownership. In other words, the responsible entity is responsible only for "monitoring and analysis" capabilities that it owns. The SDT believes this is clear but has removed "own" to reduce redundancy in the language. See summary consideration for revision.		
Associated Electric Cooperative, Inc. - JRO00088	No	FOR: TOP-001-3, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group. FOR: TOP-001-3 draft 1 clean - All Measures, including this SDT's other posted draft Standards for Comment: This Standard, along with all others revised by this project's Drafting Team, appears to word the Measures as Requirements. AECI believes the following examples represents changes that would be more conformant with other NERC Standard revisions: REPLACE: "M1. Each Transmission Operator shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area." WITH: "M1. Examples of evidence may include, but is not limited to: dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that may be used to determine that it acted, or directed others to act by issuing Operating Instructions to address its reliability functions within its Transmission Operator Area."

Organization	Yes or No	Question 7 Comment
		FOR: TOP-001-3 draft 1 clean, all references to Load-Serving Entity REMOVE: “Load-Serving Entity” from: Applicability Section 4.5, Requirement R3 and Measurement M3, Requirement R4 and Measurement M4, Requirement R5 and Measurement M5, Requirement R6 and Measurement M6. RATIONALE: See NERC Website, Program Areas & Departments, Compliance & Enforcement, Compliance Analysis and Certification, Risk-Based Registration Initiative, “RBR Design 20140602 FINAL”, “Appendix A - Risk-Based Registration Threshold Reviews”, pages A-3 thru A-6, Section “Load-Serving Entity”, on recommendations for removal based upon lack of Reliability Related Functions performed. FOR: TOP-001-3 draft1 clean, definition for Reliability Directive REPLACE: Rationale for definition for Reliability Directive being dropped WITH: Earlier definition for Reliability directive RATIONALE: AECI strongly advises this SDT and all of Industry, to reconsider this current draft’s implication that all Operating Instructions are of equal weight, pertaining to options for discussion, where equally or more effective solutions could and should be made available for discussion by the issuer. This current draft’s language does not allow options for reconsideration, when FERC itself often cites possible solutions by closing with “or an equally effective and efficient solution”. We earnestly plead with the SDT to carefully reconsider all instances where their wording choices currently bind the recipients of any Operating Instruction with absolutely no choice beyond blind complicity in all instances where the Instruction is physically feasible, safe, and legal. AECI believes such language, executed literally, unnecessarily exposes Responsible Entities to extreme financial burden, with rare benefit to BES Reliability. This is true where equally reliable yet more cost-effective solutions in fact existed, yet could not be proposed without the Operating Instruction’s recipient risking violation in several of these drafted Requirements. Please note that AECI does agree that there could be times where the Issuer, particularly RCs in light of rapidly deteriorating BES Conditions, need the authority to issue some Operating Instructions that allow no discussion beyond these conditions currently cited. Yet we firmly believe the vast majority of Operating

Organization	Yes or No	Question 7 Comment
		Instructions should not carry this currently-drafted weight of no recourse upon the issuer or recipient. FOR: TOP-001-3 draft 1 clean, definition of Real-time Assessment COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller Responsible Entities to avoid unnecessary cost of compliance where Real-time Assessments are required. COMMENT: We recommend the Real-time Assessment and Operational Planning Analysis definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,...'RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of "may" provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-001-3 draft 1 clean, Effective Date COMMENT: In requirements where Real-Time Assessment was not currently required, AECI believes newly-applicable entities should be provided with 36 months to become compliant, due to time necessary for smaller entities to research, budget, and enlist in third-party services, then sufficiently train their Operators to effectively utilize their new tool for reliability and compliance. FOR: TOP-001-3 draft 1 clean, Requirements R1 and R2CAUTION: These requirements appear to dictate that no action upon the BES will be issued in any manner outside the definition of an Operating Instruction. While AECI believes the underlying intent within this language is that all changes to the BES take place with recorded three-part communications, R3 in conjunction with R1 and R2, collectively imply dictatorial rule of every issuer over every recipient any time any BES element's state changes due to an Issuer's Operating Instruction.

Organization	Yes or No	Question 7 Comment
		FOR: TOP-001-3 draft 1 clean, Requirement R3 and R5 (absolute deal-breaker for AECI)REPLACE: "statutory requirements" WITH: "statutory requirements, or has no equally or more effective alternative" RATIONALE: For most routine Operating Instructions, both Issuers and Recipients of Operating Instructions should be provided the option to have equally or more effective solutions discussed prior an ultimate action being taken. FOR: TOP-001-3 draft 1 clean, Requirement R4PROPOSED INSERTION: a new R4, immediately following R3R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]RATIONALE: This new R4, essentially equivalent to R3 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R3 proposed change accepted, the SDT and Industry may not agree that this "no further discussion" Requirement is necessary under any circumstances. We only offer it as an optional companion of the R3 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R4 (not our proposed R4 insertion) REPLACE: "reasons shown in Requirement R3."WITH: "reasons shown in Requirement R3, with exception of equally or more effective solutions." RATIONALE: AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R6PROPOSED INSERTION: a new R7 (this R7 numbering assumes a new R4 was similarly inserted) R7. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment,

Organization	Yes or No	Question 7 Comment
		regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]RATIONALE: This new R7, essentially equivalent to draft R5 yet without the option to discuss equally or more effective actions, is provided where Reliability Directives (proposed for reinsertion) have been issued, as a unique class of Operating Instructions. (AECI understands that, even with our earlier R5 proposed change accepted, the SDT and Industry may not agree that this “no further discussion” Requirement is necessary under any circumstances. We only offer it as an optional companion of the R5 change above.) FOR: TOP-001-3 draft 1 clean, Requirement R6 (original draft R6) REPLACE: “issued by that Balancing Authority.” WITH: “issued by that Balancing Authority citing one of the specific reasons shown in Requirement R5, with exception of equally or more effective solutions.” RATIONALE: Consistency with R4 AECI does not believe BES Reliability would be served by requiring that all equally or more effective solutions be discussed. FOR: TOP-001-3 draft 1 clean, Requirement R7 (deal-breaker for AECI)COMMENT: AECI fully agrees with this requirement’s preceding rationale, where insertion of “Effective’ was noted. However AECI does not agree with current R7 language that omits the referenced inclusion. As suggested earlier under R3 and R5, AECI strongly recommends that industry be afforded opportunity to raise equally or more effective solutions for discussion as part of requesting and lending assistance, over blind compliance for any requested action this is physically possible, safe and legal. FOR: TOP-001-3 draft 1 clean, Requirement R8 (deal-breaker for AECI)REPLACE: “impacted” WITH: “known impacted” RATIONALE: True extent of impact may not be obvious to a responsible entity at all times. FOR: TOP-001-3 draft 1 clean, Requirement R9 (deal-breaker for AECI)REPLACE: “outages” WITH: “planned outages” REPLACE: “negatively impacted” WITH: “known negatively impacted” RATIONALE: Consistency of this Requirement’s language with its corresponding measurement and VSL. Also, the extent of negative impact for data

Organization	Yes or No	Question 7 Comment
		absence is practically impossible to gauge, due to the current complexity of data being circulated upstream of an RC. Notification of your RC should be sufficient. FOR: TOP-001-3 draft 1 clean, Requirement R10 (deal-breaker for AECI)REPLACE: “Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.” WITH: “Each Transmission Operator shall monitor Facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas - including sub-100 kV facilities and the status of Special Protection Systems, Functionally needed to maintain BES reliability.” RATIONALE: Scope of NERC Requirements should remain pertinent to BES Reliability Functions. FOR: TOP-001-3 draft 1 clean, Requirement R11COMMENT: This requirement should eventually make its way into a BAL Standard REPLACE: “shall monitor its Balancing Authority Area, including the status of” WITH: “shall include the status of” RATIONALE: The BAL Standards already include an extensive set of requirements pertinent to the included measurements and their quality that is pertinent to performing their reliability function. Blanket inclusion of the same within this Requirement is redundant. Further, this requirement should really be handled in a different manner, perhaps as a rapid modification to an existing BAL requirement. FOR: TOP-001-3 draft 1 clean, Requirement R12REPLACE: “Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL Tv.” WITH: Each Transmission Operator shall monitor the continuous duration of exceeded limits for all identified Interconnection Reliability Operating Limits (IROLs), and act to assure they are returned to normal before to any such duration exceeds their associated IROL Tv. RATIONALE: Rephrased requirement in a positive sense. FOR: TOP-001-3 draft 1 clean, Rationale for Requirement R14REPLACE: “such an Operating Plan” WITH: “such an Operating Plan, developed per requirements within

Organization	Yes or No	Question 7 Comment
		TOP-002"RATIONALE: This is the first occurrence of the term "Operating Plan" within the Requirements of this TOP Standard. While the current Rationale for Requirement R14 does reference this SDT's white paper, the reader is currently left wondering if this is a hidden requirement for development of Operating Plan(s), or whether the requirement actually exists elsewhere within the body of NERC Standards. FOR: TOP-001-3 draft 1 clean, Requirement R15REPLACE: "of its actions to" WITH: "of its actions taken to" RATIONALE: Clarity - to differentiate that this requirement is not a repeat, to inform the RC of action(s) developed within all Operating Plans, but rather the TOP's anticipated or actual action taken to mitigate the SOL exceedance that triggered their activation of that previously communicated Operating Plan.

Response: Please see response to SERC's comments.

While the measures may use similar words to the requirements such as "shall" and "provide", the SDT disagrees that this makes the measurements like requirements and believes the choice of words is ultimately irrelevant because measurements are simply not requirements. Measurements provide lists of types of evidence that may be useful proving compliance. Furthermore, these measures are consistent with the way other NERC standards measurements are written. No change made.

There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date.

The SDT disagrees with replacing Operating Instruction with Reliability Directive and disagrees that issuance of an Operating Instruction requires "blind complicity in all instances". While it is true that Requirement R3 compels a responsible entity to comply with an Operating Instruction issued by a higher level authority, there is nothing in the requirements that says that the responsible entity cannot question the instruction after verifying through three-part communications. Even with this statement, the kind of operating structure that could arise if a lower operating authority is not required to follow the Operating Instructions of a higher level authority could cause chaos and negatively impact reliability by making following Operating Instructions optional. No change made.

Thank you for your support of the parenthetical in Real-time Assessment.

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The SDT disagrees with the use of "may" rather than "shall" in the definition of Real-time Assessment and Operational Planning Analysis. However, the SDT has made clarifying changes to the definitions based on comments. See summary consideration for revision.

The SDT disagrees with the need to extend the implementation period to 36 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this today without performing a Real-time Assessment? No change made.

The SDT agrees that every action that changes or preserves "the state, status, output, or input of an Element" will be covered under Requirements R1, R2, and R3 and does not see an issue with a lower operating authority being required to follow the instructions of a higher operating authority. If this were not the case, then instructions from a Transmission Operator to a Distribution Provider would be merely suggestions and reliability would be jeopardized by the operational chaos such an environment would create. No change made.

The SDT disagrees with the need to make a change to Requirements R3 and R5 to allow the recipient of an Operating Instruction to implement an "equally or more effective alternative". A higher level operating authority should be able to expect a lower level operational authority to follow its instructions. Hopefully, if there are multiple available solutions, the higher authority would discuss those with the lower authority before issuing them. AECI should work with its operational entities to ensure they have a relationship that allows such discussion before issuance of Operating Instructions. No change made.

Because the change to Requirement R3 was not adopted, the SDT does not believe a new Requirement R4 is necessary to apply just to Reliability Directives. No change made.

Since the change to Requirement R3 was not adopted, the proposed change to Requirement R4 is not necessary. No change made.

Because the change to Requirement R5 was not adopted, the SDT does not believe a new Requirement R7 is necessary to apply just to Reliability Directives. No change made.

Because the change to Requirement R5 was not adopted, the proposed change to Requirement R6 is not necessary. No change made.

The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
The SDT agrees that the suggested change provides additional clarity and has made the change. See summary consideration for revision. The SDT has added 'known' to the requirement as suggested. However, the SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority's or Transmission Operator's ICCP connection experiences an unexpected outage, it absolutely should be required to notify the "known" impacted entities. See summary consideration for revision. The SDT has revised Requirement R10 to provide additional clarity due to your comment and those of others. See summary consideration for revision. For Requirement R11, the suggested modifications appear to be incomplete and would result in the Balancing Authority including SPS. It is not clear what they would be included in. The SDT agrees that this requirement should eventually be in the Balancing Authority standards but that is out of scope for this project and will have to be handled by a later project. No change made. The SDT does not believe that the suggested change provides additional clarity. No change made. The SDT agrees that Requirement R14 was not intended to require development of a new operating plan but implementation of pre-developed Operating Plans and will update the rationale. See summary consideration for revision. The SDT disagrees that adding "taken" to Requirement R15 provides any additional clarification. Actions would be "taken". No change made.		
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	Definition for Real-time Assessment: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word "contracted" with "arranged". R1 - This could place a huge burden for evidence control on the entities because Operating Instruction is altering the state of any BES Facility. This responsibility is inherent to the Functional Model and does not need to be a requirement. At a minimum, recommend removal of the Operations Planning horizon tasks and narrow down focus of intent. The term "Operating Instruction" is defined for Real-time operation. SDT should review the term Transmission Operator Area because it would not include LSE, DPs, etc. R2 - Please see comments for TOP-001-3 R1 above.

Organization	Yes or No	Question 7 Comment
		R3 - Operating Instruction is too broad of a definition that would require a huge amount of evidence. The defined term refers to too many circumstances and not only to “emergency conditions.” At a minimum, this requirement should only refer to the Real-time Operations time horizon. We also recommend LSE and DPs be removed from this requirement. The LSE’s cannot perform any corrective action. Refer to Functional Model for LSEs and DPs. In addition, there is a current proposal to remove LSEs from registry. R4 - Please see comments for TOP-001-3 R3 above. R5 - Please see comments for TOP-001-3 R3 above. R6 - Please see comments for TOP-001-3 R3 above. R7 - TOP-001-1a R6 stated “available emergency assistance” and the new requirement states “shall assist”. Recommendation would be to change the language to “if requested and available.” The RC will take the appropriate actions if there is a reliability related need. Assistance should be available to BAs as well, current wording is not symmetrical. R8 - The requirement is defining operations that could result in an Emergency and may be defining the term Emergency. The examples given are not necessarily considered an Emergency, unless they were “significant” changes and unplanned. Even then, the actions may still not constitute an Emergency. R9 - M9 refers to planned outages. If that was the intent, the word “planned” should be added to the requirement. SW Outage Report Recommendation 15 specifically addressed RTCA. This requirement was expanded beyond the recommendation. Does “monitoring and assessment capabilities” refer to Real-time Assessment capabilities? New proposed language is too broad. Recommendation would be to focus on loss of RTCA capabilities. R10 - To eliminate confusion, we recommend creating two requirements with the following language:” Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and

Organization	Yes or No	Question 7 Comment
		neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” “Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” The addition of Special Protection Systems to this requirement eliminates the need for SPSs within the new Real-time Assessment term definition. R13 - It is important for Real-time Assessments to be performed, however, it is not important who does them. Recommend language: ”Each Transmission Operator shall ensure a Real-time Assessment is performed at least once every 30 minutes.” This language allows other entities (including the RC as was the case in IRO-008-1 R2) to complete the assessment, but maintains the responsibility on the TOP as desired in the rational for R13. This falls in-line with the new definition for Real-time Assessment. R14 - The term “Real-time monitoring” is not a defined term. Existing and potential operating conditions are included in the Real-time Assessment defined term. As defined, the term “Operating Plan” refers to a formal document referencing a specific scenario or potential SOL exceedance. We have a concern on how the term Operating Plan is utilized throughout the proposed Standards and how they are linked to the OPA and RTA. We recommend changing the requirement to read: ”Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified in its Real-time Assessment.” R16 & R17 - We recommend the following language: ”Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.”
Response: (1) The SDT disagrees with deleting the parenthetical from the definition of Real-time Assessment. Other commenters have found it beneficial because it does provide for additional explanation. The SDT agrees with clarifying “contracted”. A		

Organization	Yes or No	Question 7 Comment
corresponding change was made to the definition of Operational Planning Analysis for consistency. See summary consideration for revision. The SDT disagrees that Requirement R1 is intended to apply only to Real-time and that the definition of Operating Instruction is limited to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. Requirement R1 could also apply to an operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. The SDT agrees the definition of Transmission Operator Area could be interpreted to exclude Load-Serving Entities and Distribution Providers and has modified Requirement R1 accordingly. The SDT does not believe that this requirement will place an undue burden on entities but has revised the data retention requirement for operator logs. The SDT also encourages the commenter to take an active role in the review of the RSAWs for this project. See summary consideration for revision. The SDT disagrees that Requirement R2 is intended to apply only to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. It could also apply to operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. Furthermore, the SDT disagrees that the definition of Balancing Authority Area could be interpreted to exclude Load-Serving Entities and Distribution Providers. Unlike the Transmission Operator Area definition, the Balancing Authority Area definition explicitly includes Loads. The SDT does not believe that this requirement will place an undue burden on entities but has revised the data retention requirement for operator logs. The SDT also encourages the commenter to take an active role in the review of the RSAWs for this project. See summary consideration for revision. The SDT disagrees that Requirement R3 is intended to apply only to Real-time. The proposed definition of Operating Instruction is limited to those who can control actions in Real-time which would be the Reliability Coordinator, Transmission Operator, and Balancing Authority. It does not specify a time in which those actions can take place. It could also apply to operational planning decision such as instructing an equipment owner to cancel an outage or it could apply to committing a generation unit with a long lead time such as two or three days. There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date. Load-Serving Entities can perform corrective actions such as shedding Load. No change made.		

Organization	Yes or No	Question 7 Comment
See comments for Requirement R3. See comments for Requirement R4. See comments for Requirement R5. See comments for Requirement R6. The SDT agrees with the suggestion to add “and available” to the requirement and that the requirement is not symmetrical and appropriate changes have been made. See summary consideration for revision. The SDT agrees and has deleted the examples. See summary consideration for revision. The SDT has modified Measure M9 to remove “planned” as the requirement applies to both planned and unplanned outages. The SDT disagrees that the requirement is too broad and that “monitoring and assessment capabilities” would only apply to RTCA capabilities. It could also apply to SCADA or alarming as an example. See summary consideration for revision. The SDT disagrees that Requirement R10 should be split into two requirements. However, the SDT has modified the requirement for additional clarity in response to this and other comments. The SDT also disagrees that that the addition of SPS to this requirement obviates the need for SPS in the Real-time Assessment definition. This requirement is to monitor the status of an SPS and may trigger the need to perform a Real-time Assessment if an SPS were suddenly unavailable. The subsequent Real-time Assessment then should reflect that the SPS is no longer available. See summary consideration for revision. The SDT has revised the requirement language for clarification. See summary consideration for revision. The SDT disagrees. Real-time monitoring can produce alarms that would precipitate action. No change made. The SDT believe the proposed changes to R16 and 17are largely unnecessary, do not provide additional clarity and actually remove the true reliability intent of the requirement. The true reliability intent is that the System Operator has authority over his tools. The proposed changes removed System Operator. Furthermore, approval authority would grant authority to approve, deny or cancel planned outages. Monitoring and Real-time Assessment capabilities could include hardware, analysis tools and the EMS. However, it may not include telecommunication so the SDT is adding telecommunication to the requirements. See summary consideration for revision.		
MRO NERC Standards Review Forum	No	Comments: In R1 and R2, the wording of “reliability function” is used and the NSRF suggest replacing it with “to maintain system stability”. This is more in line with the definition of an Operating Instruction. If “reliability function” is maintained, we

Organization	Yes or No	Question 7 Comment
		believe that any conversation or discussions concerning what the entity's function is, would be construed as an Operating Instruction. We believe this is not the intent of the SDT. R4 is predicated on R3 and only allows entities the inability to perform the issued Operating Instruction based on "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements". The entity then must cite which specific reason why they cannot perform the Operating Instruction. The NSRF does not agree with this due to the limited possibilities for not performing the Operating Instruction. The NSRF recommends deleting "citing one of the specific reasons shown in Requirement R3", as this wording does not prevent instability, uncontrolled separations or Cascading outages. We do not need rules this specific, the issuing entity can always ask why the receiving entity cannot perform the Operating Instruction. During a real time event, the TOP only cares about the mitigating actions that they have available in order to maintain system stability. If a requested action cannot be accomplished by the requested entity, the TOP will quickly move to their next mitigating action. There is no need for small talk of "why" the requested action cannot be performed. The NSRF believes this was a partial cause of the 2003 blackout. R8. The NSRF understands the intent of R8 and recommends the words "system or equipment" be added prior to operations. Recommended changes provide clarity as, "...of its actual or expected system or equipment operations that result in...". This provides clarity to what type of operations the Requirements is referring to. R8. Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected system or equipment operations that result in, or could result in, an Emergency. Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load. R9 - Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their

Organization	Yes or No	Question 7 Comment
		contingency analysis capabilities after the functionality is lost. Therefore, the requirement should be revised to only address forced or unexpected outages. Recommend that R9 read as: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities R13 - Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains the requirement, the NSRF recommends developing a performance based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example - CPS1 / CPS2 BA performance metrics.

Response: (1) The SDT has revised the requirement to add clarity and consistency with the IRO standards. See summary consideration for revision.

The SDT agrees in that in Real-time operations the Transmission Operator primarily only needs to know that an action could not be implemented. Why is less important. This makes the requirement consistent with Requirement R6. The requirement has been modified accordingly. See summary consideration for revision.

The SDT does not believe that the suggested change adds any additional clarity. No change made.

While the SDT understands that there were significant issues identified in the Southwest Outage Report regarding the failure of Contingency analysis, the SDT believes the issue is much broader than just forced outages and Contingency analysis. An outage of SCADA could have just as big an impact for example. Whether the outage is planned or forced is also not relevant because either

Organization	Yes or No	Question 7 Comment
type of outage is loss of capability that could impact operations. The requirement does not compel RTCA and there is no existing requirement to have RTCA. It is necessary to communicate the outage of key tools and monitoring capabilities. No change made. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Colorado Springs Utilities	No	1. R7 - "Effective" is not included in the requirement language as indicated in the rationale.

Organization	Yes or No	Question 7 Comment
		2. R13 needs additional time for implementation. Recommendation for 3 years from approval. We voted negative on this standard because we think that the implementation period needs to be longer. 3. R14 - There is currently no requirement to have a plan, so how can entities be required to follow a plan they are not required to create? Is a generic SOL mitigation plan satisfactory?
Response: 1. The SDT has revised the language based on your and other comments. See summary consideration for revision. 2. The SDT disagrees with the need to extend the implementation period to 36 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made. 3. The SDT agrees that Requirement R14 was not intended to require development of a new Operating Plan but implementation of pre-developed Operating Plans and will update the rationale to explain this. Some minor modifications to the requirement have also been made for clarity. See summary consideration for revision.		
SERC OC Review Group	No	1) Request clarification on who “others” are for R1 & R2, “RC shall act, or direct others to act,”. Suggestion: “directs others (as identified in R3) to act”. Current: “shall act, or direct others...” Suggested: “shall act, or direct others (as identified in R3)...” 2) R7 is missing the use of the word “effective” that was referenced in the rationale. 3) In R9, remove “and negatively impacted interconnected NERC registered entities” because each entity does not always know who may be impacted. (i.e., entity in SERC is providing data to NYISO. Is NYISO an impacted entity for loss of the data?) Also, insert ‘planned’ before outages in Requirement to be consistent with M9 and the VSL for R9.Current: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment,

Organization	Yes or No	Question 7 Comment
		control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” Suggested: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” 4) In the R13 VSLs, there is concern that the bandwidth between “lower” and “severe” VSL is only 15 minutes. Suggestion: expand bandwidth. See also response on IRO-008-2, question 3 above.
Response: 1) The SDT does not believe that “others” in Requirements R1 and R2 requires any further clarification. The commenters seem to correctly understand that Requirements R3 and R5 are complimentary and define who has to respond to the Transmission Operator and Balancing Authority in Requirements R1 and R2. No change made. 2) The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision. 3) The SDT disagrees and believes that the Transmission Operator is in a position to know which outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact other entities. It should be limited to those areas that are impacted by the loss of their transmission, generation, or Load within its Transmission Operator Area. No change made. 4) See response to Q14.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	R1 and R2 - Southern suggest that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 - The Rationale section for Requirement R7 states that the word ‘Emergency’ was deleted and the word ‘Effective’ was added to the Requirement language. The word ‘Effective’ is missing from the Requirement language. R8 - Southern suggests that the phrase ‘could result in’ is too open ended and assumes that operations takes place as expected and does not account for failures

Organization	Yes or No	Question 7 Comment
Generation and Energy Marketing		and equipment during the operations such as faulted breaker, or human performance errors. R9 - Add the word ‘planned’ to Requirement language to match Measure language. R9 - The phrase ‘negatively impacted Interconnected NERC registered entities’ seems broadly generic. Southern suggests adding the words, ‘other affected adjacent BAs and TOPs’. Suggested Requirement language: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and other affected adjacent BAs and TOPs, of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Suggested Measure language:M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and other affected adjacent BAs and TOPs, of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation. R10 - Southern recommends adding the words ‘as deemed necessary by the TOP’ after the words sub-100 kV facilities which would make this TOP requirement consistent with the corresponding RC Requirement in IRO-008. Suggested Requirement language: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities, as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.

Organization	Yes or No	Question 7 Comment
		Suggested Measure language:M10. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area including sub-100 kV facilities as deemed necessary by the TOP, to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area . R11 - Southern suggests that the SDT coordinate with the SPS drafting team on the use of RAS versus SPS for Requirement R11 as well as throughout the standards included in this project. R14 - Southern suggest deleting the phrase, 'as part of', and adding 'as a result of'....Suggested Requirement language: R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as a result of its Real-time monitoring or Real-time Assessment. Suggested Measure language: M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as a result of its Real-time monitoring or Real-time Assessments. This evidence could include, but is not limited to, dated computer logs showing time the Operating Plan was initiated, dated checklists, or other evidence. R15 -Southern suggest that R15 as written has the potential for adding to Reliability Risk as it could cause the operator to spend time notifying the RC for compliance reasons rather than responding to the SOL exceedance. Instead, we suggest the requirement be re-written to have the TOP inform its RC of its inability to return the system to within limits when an SOL has been exceeded. Suggested Requirement language: R15. Each Transmission Operator shall inform its Reliability Coordinator of its inability to return the system to within limits when an SOL has been exceeded.

Organization	Yes or No	Question 7 Comment
		Suggested Measure language: M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of its inability to return the system to within limits when an SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recording, or dated computer printouts. R16 and R17 - These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 - These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 - There is confusion in the Industry of what the current term 'derived limits' means. The SDT should take this opportunity to clarify whether 'derived limits' is referring to SOLs, IROLs. If this is the case, then why use the term, 'derived limits'?

Response: R1 and R2 – The SDT is attempting to create results-based standards. Without specific feedback, the SDT is unable to respond further.

The SDT agrees that the language in the rationale box and Requirement R7 do not match. The rationale has been adjusted accordingly. The SDT has made other clarifying changes to the requirement based on comments. See summary consideration for revision.

R8 - The SDT believes that the phrase is question is needed for reliability. If an entity has reason to believe that it has a potential condition that could result in an Emergency, it should inform the Reliability Coordinator and other potentially impacted entities in the interest of reliability. No change made.

Organization	Yes or No	Question 7 Comment
R9 - The SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority or Transmission Operators ICCP connection experiences an unexpected outage, it should be required to notify the other impacted entities. The SDT has deleted 'planned' from the Measure. See summary consideration for revision. R9 – The SDT agrees and has changed the requirement accordingly. See summary consideration for revision. R10 - The SDT agrees that the language of the requirement could be made clearer and has modified the language to show that the Transmission Operator identifies a subset of neighboring Transmission Operator facilities that should be monitored. See summary consideration for revision. R11 – The cited change has not been approved. If, and when, it is approved, that SDT will need to revise all standards and requirements accordingly. Until such time as the change is approved, the 2014-03 SDT must continue to use approved terms. No change made. R14 - The SDT has modified Requirement R14 for clarity based on comments of other standard. See summary consideration for revision. R15 – The SDT disagrees that Requirement R15 has the potential to cause the operating entity to notify the Reliability Coordinator for compliance reasons other than an SOL exceedance. The language is clear that the Transmission Operator shall notify the Reliability Coordinator "of its action to return the system to within limits when an **SOL was exceeded**" (emphasis added). This is past tense. Notification is not required until after the exceedance has occurred. No change made. R16 and R17 - The SDT agrees that the parallel requirements in proposed IRO-002-4 Requirement R3 and proposed TOP-001-3 Requirements R16 and R17 should be consistent and have made appropriate changes. See summary consideration for revision. R16 and R17 - The SDT does not believe that additional clarification to is needed to indicate that the Reliability Coordinator has authority over the Transmission Operator and Balancing Authority and can override its decision to approve outages of its monitoring and analysis capabilities. The Reliability Coordinator already has the authority to issue Operating Instructions to these entities of needed. No change made. R18 - The SDT agrees that derived limits can be made more specific and has modified the language of the requirement. See summary consideration for revision.		
Dominion	No	While Dominion agrees conceptually with Requirements 5 and 6 we do not believe they belong in the TOP family of standards.

Organization	Yes or No	Question 7 Comment
		Dominion does not agree with Requirement 7 as we do not see how it is substantially different from R3 and R5 under this standard and we expect that, in many cases, such assistance is likely to come in the form or an Operating Instruction issued by a Reliability Coordinator, in which case the recipient must comply. We oppose because this requirement does nothing to increase reliability; it only increases compliance risk for the entity. Dominion does not agree with R10 as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We could support if revised as indicated “Each Transmission Operator shall monitor BES Facilities within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area and the status of Special Protection Systems within its Transmission Operator Area.” It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. Dominion has concerns with inclusion of Generator Operator in Requirement 18. The only limits the GOP is aware of are those for the facility it operates. The GOP is not typically provided limits or ratings for facilities it does not operate and, where it is provided such, it has only that single value and therefore no derived difference can be determined. For these reasons, we suggest Generator Operator be deleted from this requirement.

Response: The SDT ultimately agrees that Requirements R5 and R6 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

Requirement R7 differs from Requirement R3 in that Requirement R3 does not allow a Transmission Operator to Transmission Operator Operating Instruction. Requirement R5 is not relevant since it involves following a Balancing Authority’s Operating Instructions and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued Operating Instruction and will remove the Balancing Authority from the requirement. The SDT

Organization	Yes or No	Question 7 Comment
has made modifications to this requirement based on other comments as well. See summary consideration for revision. The SDT also refers the commenter to approved EOP-001-2.1 and to on-going work in Project 2009-03. The SDT has revised Requirement R10 based on comments received. See summary consideration for revision. R18 - The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs. See summary consideration for revision.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). Also, GOPs do not need to be listed in R18 since their role in operating to the most limiting parameter is to follow the directives of the TOP and BA.
Response: See response to FRCC comments. The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs, IROLs, and Facility Ratings. See summary consideration for revision.		
Duke Energy	No	Duke Energy does not agree with the proposed changes for TOP-001-3. Specifically, we have concerns that R1 and R2 as written do not appear to be Results-Based as laid out in the Rules of Procedure. The requirement that the TOP/BA "act" to ensure the reliability of the its area is not only a requirement that the entity do its job for which other requirements are applicable, but also a requirement that could be interpreted to require that the TOP/BA "act" to cover the full scope of any related reliability tasks listed under the NERC Functional Model. We believe such language should be removed and that the requirements should focus strictly on the communication desired when needed to ensure the reliability of the TOP or BA area.

Organization	Yes or No	Question 7 Comment
		R1: The TOP is already required to act in other applicable standards. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R2: We disagree with the placing of the Balancing Authority here in this standard. We feel this is better placed within the BAL standard family. We believe the requirement should continue to be bound to the defined scope of a Reliability Directive. R3: The definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. R4: No Comment R5: See Comment on R3 R6: See Comment on R3 R7: See Comment on R3 R8: Duke Energy suggests removing the reference to the examples and suggests the following: ”Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.” We believe the examples are not necessary in this requirement. R9: Duke Energy suggest the following revision: ”Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected Applicable entities of planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” We believe that “negatively impacted” is ambiguous and lacks clarity and suggest removing “negatively”. In addition, we believe using “Applicable entity” is a more

Organization	Yes or No	Question 7 Comment
		appropriate term to use than NERC registered entities. Finally, we suggest adding “planned outages” in order to be consistent with Measure 9. R10: Duke Energy believes that this requirement should be separated into two different requirements and suggests the following language: “Each Transmission Operator shall monitor Facilities, and identified sub-100 kV facilities, within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area. Each Transmission Operator shall monitor the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas necessary to determine any potential SOL and IROL exceedances within its Transmission Operator Area.” We believe separating this into two requirements will provide better clarity on the expectations that should be monitored by a TOP. R11: We believe that this requirement is better suited in the BAL family of standards. R12: No comments R13: While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC’s transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a TOP to transition to its backup control center. If a TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement. R14: Duke Energy suggests removing “Real-time monitoring” from this requirement.

Organization	Yes or No	Question 7 Comment
		R15: No comments R16/R17: - Duke Energy suggests combining the two requirements and rewording as follows: "Each TOP and BA shall have the authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools." The removal of System Operators is necessary in the context of this requirement. Per the NERC definition, System Operators are the individuals "who operates or directs the operation of the Bulk Electric System (BES) in Real-time." System Operators work in a real-time environment and thus is in direct conflict with the use of the Operations Planning Time Horizon (next day to seasonal) in this requirement. In addition, we believe the TOP and BA should have the authority to approve, deny or cancel these types of outages in R3, not just the individual System Operators. There can be instances where a program tool used to perform a next-day study analysis could be requested to be taken out of service for maintenance and the TOP and BA needs to have the authority to deny that request. R18: No comments

Response: (1) The SDT has attempted to create results-based standards. In response to other comments, the SDT did modify Requirements R1 and R2 to reflect that the true requirement is to act to maintain reliability not "to address its reliability functions". Furthermore, the "communication desired when needed to ensure the reliability of the Transmission Operator or Balancing Authority area" will be covered under proposed COM-002-4. See summary consideration for revision.

(2) The SDT disagrees that the requirement to act in Requirement R1 is already covered in other Reliability Standards and without a specific reference do not see justification for modifying Requirement R1. No change made.

(3) The SDT ultimately agrees that Requirements R2, R5, R6, and R11 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

(4) See response to Q14.

(5) For Requirements R5, R6, and R7, see comment on Requirement R3.

Organization	Yes or No	Question 7 Comment

(6) The SDT has deleted the examples. See summary consideration for revision.

(7) The SDT agrees and has changed the language of the requirement to remove 'negatively'. The SDT has removed planned from Measure M9 to make the measure consistent with the requirement. Regardless of the reason for the outage, impacted entities need to be notified. See summary consideration for revision.

(8) The SDT agrees that the language of Requirement R10 could be clearer and has modified the language accordingly. The SDT does not believe it is necessary to split the requirement into two requirements. See summary consideration for revision.

(9) The SDT ultimately agrees that Requirement R11 belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

(10) The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The

Organization	Yes or No	Question 7 Comment
SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT believes that SOLs can be identified by Real-time monitoring as well as through Real-time Assessments. No change made. (11) The SDT believe the proposed changes to Requirement R16 and R17 do not provide additional clarity and actually remove the true reliability intent of the requirement. The true reliability intent is that the System Operator has authority over his/her tools. The proposed changes removed System Operator. Furthermore, approval authority would grant authority to approve, deny, or cancel planned outages. No change made.		
PPL NERC Registered Affiliates	No	PPL does support the standard. We recommend the drafting team use only the term, ‘Facility Rating’ and not use the term ‘derived limit.’ This will provide for consistency is use of one term. Requirement #18, “Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits,” should be changed to ïƒ “, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in Facility Ratings.”
Response: The SDT has modified the requirement to reflect that derived limits are SOLs. See summary consideration for revision.		
Bureau of Reclamation	No	Reclamation disagrees with the use of the term Operating Instruction in IRO-001-4 R1. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Often Transmission Operators may not be aware of generation equipment constraints or other obligations (e.g. water delivery schedules for hydroelectric projects). Reclamation believes that IRO-001-4 should establish Transmission Operator authority to issue Reliability Directives to address an Emergency or avoid an Adverse Reliability Impact.

Organization	Yes or No	Question 7 Comment
Response: An Operating Instruction would include what was previously classified as directives, as per its definition, so proposed TOP-001-3 Requirements R1 and R2 already give the Transmission Operator authority to issue directives. No change made.		
BC Hydro and Power Authority	No	BC Hydro's concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of "Operating Instructions" broadens to non-emergency situations. Requirement R3 and R4 have the BA's complying with TOP's Operating Instructions. BC Hydro's concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no "out" clause based on reliability conflicts - such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an "out" clause.
Response: The SDT disagrees that Operating Instruction is too broad and that the standard should only apply in Emergencies. Failure to properly implement an Operating Instruction could be the initiating action that leads to an Emergency. This was the case in the September 2011 Southwest Outage. Also, an Operating Instruction would include what was previously classified as directives, as per its definition, so proposed TOP-001-3 Requirements R1 and R2 already give the Transmission Operator authority to issue directives. No change made. In the event that there is a conflict in Operating Instructions, the recipient can cite the clause "unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements" in Requirements R3 and R5 to resolve the situation. No change made.		
SPP Standards Review Group	No	We recommend the Real-time Assessment and Operational Planning Assessment definitions include the following change: 'The assessment may reflect inputs including, but not limited to: load, generation output levels,...' This will provide some flexibility for the TOP and BA to factor in those variables which can potentially impact

Organization	Yes or No	Question 7 Comment
		the assessments without being so overly prescriptive that they must be included in all assessments. We recommend deleting Requirements R1 and R2 because they are redundant to the entire collection of Reliability Standards. If a Transmission Operator or Balancing Authority does not do what is being required in R1 and R2, they are non-compliant with many of the remaining standards. This then appears to be redundant and these requirements should be deleted based on Paragraph 81 considerations. Insert a 'to' between the 'do' and the 'due' in the last line of the Rationale for Requirement R3. Replace 'Transmission Operator' in the 3rd line of M5 with 'Balancing Authority'. Replace 'Balancing Authority' in the 6th line of M6 with 'Transmission Operator'. We recommend the following language for Requirement R8: 'Each Transmission Operator shall inform its Reliability Coordinator, impacted Balancing Authorities, and impacted Transmission Operators of actual or expected conditions that it has identified which could potentially result in an Emergency.' Requirement R9 requires the Transmission Operator to notify negatively impacted NERC registered entities. This is too broad and needs to focus on those entities which the Transmission Operator is aware that they are using the data and that the impact is of some significance. Additionally, this could prove to be burdensome on the industry for those situations where telemetry is repeatedly dropping out and restoring itself. We recommend the drafting team address the concept of significance and include a minimum down-time such as 30 minutes which is already incorporated in EOP-004-2, Attachment 1. Requirement R10 requires the Transmission Operator to monitor Facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area. While we understand the intent of the requirement, we have concerns that in an audit situation or following an event, the question will be did the Transmission Operator go far enough into the neighboring Transmission

Organization	Yes or No	Question 7 Comment
		Operators Area. How far is far enough in this situation? Where does the responsibility for this monitoring transfer from the Transmission Operator to the Reliability Coordinator? Additionally, there appears to be redundancy between Requirement R10 and Requirement R1 in TOP-003-3 in that the later requests the data to allow for Real-time monitoring. We suggest eliminating Requirement R10. If the requirement must remain, we recommend the drafting team consider referring to the data requirement in TOP-003-3, Requirement R1 and specifically state that the extent of the data to be requested from neighboring Transmission Operators be determined by the Transmission Operator. Replace ‘Tv’ in the 3rd line of M12 with a subscripted 'Tv’. Regarding Requirement R13, please see our previous comments in response to Question 3 on IRO-008-2 associated with the 30-minute Real-time Assessment requirement. A similar argument holds for the TOP in TOP-001-3. Additionally, in the situation with smaller Transmission Operators, there may be an issue with the time required to acquire Real-time Assessment capabilities. For those smaller entities which may not be currently performing this role, it may take longer than a year for them to obtain this capability. Additional time should be provided in this situation. For example, TOP-003-3, Requirement R5 allows for more time for those entities which are not currently providing the data required in TOP-003-3, Requirement 1. A similar allowance should be included in Requirement R13. Replace ‘Real-Time’ in the 2nd line of M13 with ‘Real-time’. Requirements R16 and R17 require the Transmission Operator and Balancing Authority, respectively, to provide its System Operators with the authority to approve planned outages of its monitoring and assessment capabilities. Does this apply to a single RTU or is it intended to cover only the full range of EMS capabilities? What is meant by ‘derived limit’ in Requirement R18?

Organization	Yes or No	Question 7 Comment

Response: The SDT agrees and has made the suggested change. See summary consideration for revision.

The SDT disagrees that the requirement to act in Requirements R1 and R2 is already covered in other reliability standards and without a specific reference do not see justification for modifying Requirements R1 and R2. However, some clarifying changes to reflect that the responsibility is to act to preserve reliability have been made. See summary consideration for revision.

The SDT has made a grammatical change to the rationale address your concern.

The SDT agrees and has made the suggested change. See summary consideration for revision.

The SDT agrees and has made the suggested change. See summary consideration for revision.

The SDT does not see that the proposed language provides any added clarity in Requirement R8. No change made.

The SDT disagrees that the requirement is too broad and believes that the Transmission Operator is in a position to know which entities outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact. It should be limited to those areas that are impacted by the loss of their transmission, generation, or load within their Transmission Operator Area. However, the SDT does agree that the requirement should be consistent with other standards. See summary consideration for revision.

The SDT has modified Requirement R10 to provide further clarification. The Transmission Operator will ultimately be responsible for determining what Facilities in neighboring areas they will need to monitor to assess the impact on the Transmission Operator Area. See summary consideration for revision.

The SDT disagrees that proposed TOP-003-3 Requirement R1 and proposed TOP-001-3 Requirement R10 are redundant. Proposed TOP-003-3 Requirement R1 is about the request for data. Proposed TOP-001-3 Requirement R10 is about monitoring and utilizing the requested data. The requirements are complementary. No change made.

The SDT has modified Measure M12 as requested. See summary consideration for revision.

For Requirement R13, see comment regarding IRO-008-2 in Q3.

The SDT disagrees with the need to extend the implementation period for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made.

Organization	Yes or No	Question 7 Comment
The SDT has modified measure M13 as requested. See summary consideration for revision. Requirements R16 and R17 could certainly apply to a single RTU if it is impactful to reliability. Requirement R18 has been modified to clarify the requirement. See summary consideration for revision.		
ACES Standards Collaborators	No	(1) For Requirement R3, we question the phrase "cannot be physically implemented" and how that term would differ from violations of safety or equipment requirements. We recommend the SDT provide examples to support the new proposed language. (2) We recommend combining R4 with R3 and R6 with R5. Language could be easily added to notify the inability to comply with the Operating Instruction. This is the same comment for combing R6 with R5. (3) For Requirement R7, we question the need for this requirement since an entity is already subject to comply with Operating Instructions. Operating Instructions would include assistance relating to emergency procedures. This requirement is redundant and should be removed. (4) Requirement R8 is problematic as currently written. At what point must a TOP notify the RC, BA, and other TOPs of "expected operations that could result in an Emergency?" We recommend focusing on actual operations that result in actual Emergencies. Furthermore, examples do not belong in a requirement and should be moved to the application guidelines. (5) For Requirement R9, what is the timing of notifications? The requirement does not define "negatively impacted interconnected NERC registered entities" and therefore is vague. Can other entities be positively impacted? We recommend clarifying this requirement. (6) We disagree with Requirement R10 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. TOP-001-3 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly

Organization	Yes or No	Question 7 Comment
		impact reliability, are redundant, and handle data requests and submittals. Further, asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards. (7) For Requirement R13, we ask the SDT to clarify that registered entities are not required to install real-time state estimation to perform its Real-time Assessments and can rely on other methods to perform the assessment such as reviewing its RC's results. (8) For R14, the language is confusing. We suggest changing "as part of its" to "identified in its." This will make clear that the SOL is identified in the Real-time monitoring or Real-time Assessment. (9) For Requirement R15, we question the value of TOPs stopping what they are doing to alleviate a SOL violation to call the RC to tell them their plan. It seems to make better sense for the TOP to focus on the returning the SOL to within limits when it is exceeded and contact the RC if the TOP enters into an Emergency. (10) For Requirement R18, how does the drafting team define "derived limits"? This requirement is unnecessary because the TOP, BA, and GOP are required to comply with Operating Instructions.

Response: (1) Regarding the term "cannot be physically implemented" in Requirement R3, it is intended to cover the category that has always been a gap in the standard. For example, if a Transmission line is out of service and wire has been removed for re-conductoring, the line cannot be physically put back into service. This is not really a safety, equipment limit, regulatory or statutory issue. No change made.

(2) The SDT does not believe that combining Requirement R4 with Requirement R3 and Requirement R6 with Requirement R5 provides any additional clarity. No change made.

(3) The SDT disagrees that Requirement R7 is redundant with other requirements in this standard and unneeded. Requirement R7 differs from Requirement R3 in that Requirement R3 does not allow a Transmission Operator to Transmission Operator directive. Requirement R5 is not relevant since it involves following a Balancing Authority's directives and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as

Organization	Yes or No	Question 7 Comment
		partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued Operating Instruction and will remove the Balancing Authority from the requirement. The SDT has made other modifications to the requirement based on other comments as well. See summary consideration for revision. (4) The Transmission Operator must notify the Reliability Coordinator when it is in an Emergency or anticipates that it could quickly be in an Emergency due to some event. For example, if an SPS was suddenly and unexpectedly disarmed, there may not yet be an Emergency but if a Contingency were to happen, there likely would be an Emergency. The Reliability Coordinator needs to be aware of these situations. The SDT agrees that the examples for Requirement R8 are not necessary and has deleted them. No additional changes beyond removing the examples made. See summary consideration for revision. (5) The SDT has made clarifying changes to Requirement R9 including removing "negatively". See summary consideration for revision. (6) The SDT has modified Requirement R10 for clarity. See summary consideration for revision. (7) The SDT was very intentional in writing the definition of Real-time Assessment to allow for third-party services. Thus, Requirement R13 is not intended to require a Transmission Operator to have state estimation and real-time contingency analysis. Other methods may be relied upon included utilizing the Transmission Operators Reliability Coordinator's results. The SDT has modified Requirement R13 and the definition of Real-time Assessment to further clarify this understanding. See summary consideration for revision. (8) Requirement R14 has been modified as requested along with additional modifications based on other comments. See summary consideration for revision. (9) The SDT agrees that the Transmission Operator should not stop what it is doing to alleviate a SOL to notify the Reliability Coordinator of its actions in Requirement R15. However, the SDT does believe there will be time in between actions or immediately after taking an action but prior to full implementation of said action (e.g., re-dispatch) to notify the Reliability Coordinator. No change made. (10) The SDT has clarified Requirement R18. Derived limits are SOLs. The SDT disagrees that the requirement is not needed because Transmission Operators and Balancing Authorities must follow directives. However, the SDT has removed Generator Operator based on this reasoning. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
ISO/RTO Standards Review Committee (SRC)	No	Regarding R2, did the SDT consider whether putting a “transmission operations” requirement on a Balancing Authority was appropriate? We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that “Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area.” This requirement seems out of place. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP’s and OC’s recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator (in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest removing the BA from R7. Requirement R9 stipulates that: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.”

Organization	Yes or No	Question 7 Comment
		The last part appears to be unclear as the “affected entities” can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the “associated communication channels between affected entities” will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to “between it and the affected entities”. Requirement R11 is out of place for the similar reasons indicated for R2, above. We suggest removing this requirement, or move it to the appropriate BAL or EOP standard. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart. Comments R1: We do not agree with the rationale for this requirement. If an RC does not act he will be in violation of other requirements and therefore a possible double jeopardy. The previous requirement R3, obligated an RC to have authority from someone to ensure that they could take actions which is now absent. Comment R7: We believe the previous language should be retained to limits the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. Comment R8: Should remove “or could result in” since it is unmanageable to inform all possibly impacted entities of all possible contingencies.

Organization	Yes or No	Question 7 Comment
		Comment R9: How does one access a potential negative impact? To what extent would negatively impacted entities need to be notified? Could it involve even governor response? Also, is this for planned or actual outages? The measure states planned, the requirement doesn't. How will this coordinate with COM-001 R3? Comment R10: The phrase 'including sub-100 kV' is not needed. If the sub 100 kV facility impacts the BES in such a manner, it should be labeled a BES facility per the inclusions in the new definition. Comment R13: We ask that the drafting team confirm that Real-time Assessments are not limited to software applications specifically a contingency analysis tool. How is this coordinated with EOP-004 for reporting tool outages exceeding 30 minutes?

Response: Requirement R2 is intended to require the Balancing Authority to focus on its reliability functions (i.e., balancing Load, interchange, generation) not transmission operations. No change made.

The SDT ultimately agrees that Requirements R2, R5, R6, R11, and R17 belong in the BAL standards but there is no current active project that with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

The SDT agrees and has removed Balancing Authority from Requirement R7. See summary consideration for revision.

The SDT has modified Requirement R9 but does not agree that a time limit is needed. See summary consideration for revision.

The SDT disagrees that a Balancing Authority should not be included in Requirement R18. While a Balancing Authority may not derive SOLs, they certainly do operate to them in certain cases. No change made.

Requirement R1 does not apply to the Reliability Coordinator. No change made.

The SDT believes Requirement R7 has been structured appropriately. First, the requester has to already have implemented its emergency procedures so it is an Emergency. Second, the requirement includes several caveats (i.e., statutory, regulatory, safety, equipment limits, and inability to physically implement). If none of these conditions are met, why would the assisting entity not provide additional assistance? The SDT has made changes for clarity based on comments received. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment

Requirement R8 does not require the Transmission Operator to notify impacted entities of all possible Contingencies. Most Contingencies will not result in an Emergency. Only a small subset will. The SDT believes it is appropriate to notify the impacted entities of these Contingencies. No change made.

Requirement R10 has been modified for clarity based on comments received. See summary consideration for revision.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
Bonneville Power Administration	No	Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the Standard as an appendix. BPA believes the language in requirements R8 and R14 is too ambiguous and open-ended. As a result, this would likely lead to decisions based on assumptions. BPA suggests both requirements be tied to an operating procedure or process, which, in turn, can be left to each applicable entity to define. BPA also opposes language in the Standard which has the potential to conflate events that are happening with events that have a high probability of happening. BPA suggests the drafting team clearly separate these two concepts, and include parameters for possible events, so that applicable entities are not required to predict all possible future events.
Response: The SDT agrees to include the whitepaper in the application guidelines or an appendix of the standard. The SDT has made modifications to both Requirements R8 and R14 that provide clarifications. See summary consideration for revision. Due to the non-specificity of the last comment, the SDT has no response. The SDT has no idea which requirements are problematic for you and can't address your concern as a result. No change made.		
Georgia System Operations	No	R1 and R2 - Request that Requirements 1 and 2 are high level and generic and that the requirements do not seem results-based. R7 - The Rationale section for Requirement R7 states that the word 'Emergency' was deleted and the word 'Effective' was added to the Requirement language. The word 'Effective' is missing from the Requirement language. Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, we believe the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other Standards closely

Organization	Yes or No	Question 7 Comment
		associated such as COM-002-4. We recommend replacing the terms "reliability of the Interconnection" with the terms "reliability of the Bulk Electric System (BES)". The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment "affecting the reliability of the BES" is not very routine. The intent of this requirement should be for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency "affecting the reliability of the BES". The use of the NERC term "Emergency" would capture this intent. We propose the language "[during an Emergency]" be added after "....shall comply with each Operating Instruction issued by its Transmission Operator(s) [ ] ". R8 - We suggest that the phrase 'could result in' is too open ended and assumes that operations takes place as expected and does not account for failures and equipment during the operations such as faulted breaker, or human performance errors. R9 - Add the word 'planned' to Requirement language to match Measure language.R9 - The phrase 'negatively impacted Interconnected NERC registered entities' seems broadly generic. GSOC suggests adding the words, 'other affected adjacent BAs and TOPs'. R16 and R17 - These requirements only address planned outages of monitoring and assessment capabilities while the corresponding RC requirement in the IRO standards address maintenance of such capabilities as well. The SDT should review for consistency purposes. R16 and R17 - These requirements state that the TOP and BA shall provide its System Operators with the authority to approve planned outages of its own monitoring and analysis capabilities. Is clarification needed to reflect that the RC can override the authority given to System Operators as stated in R1 of EOP-002-2.1 (The RC has the

Organization	Yes or No	Question 7 Comment
		ultimate responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and responsibility and shall exercise specific authority to alleviate capacity and energy emergencies.) R18 - There is confusion in the Industry of what the current term ‘derived limits’ means. The SDT should take this opportunity to clarify whether ‘derived limits’ is referring to SOLs, IROLs. If this is the case, then why use the term, ‘derived limits’?

Response: The SDT has made every effort to employ results-based methods in the revisions. No change made.

The SDT agrees and has updated the rationale for Requirement R7.

Standards are written for the reliability of the BES so the SDT finds the suggested change to be redundant. No change made.

The SDT disagrees that Requirements R3 and R5 should only apply in Emergencies as failure to properly implement an Operating Instruction could be the initiating action that leads to an Emergency. This was the case in the September 2011 Southwest Outage. However, in response to other comments, the SDT has modified Requirements R1 and R2 to reflect that these are Operating Instructions issued to preserve reliability on the BES. See summary consideration for revision.

The SDT disagrees that Requirement R8 is too broad. Requirement R8 appropriately requires the Transmission Operator to notify impacted entities of operations that could result in an impact. This requirement and the standard as a whole does consider the impact of stuck breakers along with other impactful contingencies. A Transmission Operator is required to operate within SOLs and IROLs. Approved FAC-011 Requirement R3, Part 3.3 already requires the Reliability Coordinator’s SOL methodology to include multiple Contingencies such as a stuck breaker. No change made.

The SDT has removed planned from Measure M9 to match the requirement. Notice of outages of tools and monitoring capabilities is important regardless of the cause. The SDT disagrees that the requirement is too broad and believes that the Transmission Operator is in a position to know which entities outages of its telecommunications, control equipment, and monitoring and assessment capabilities will impact. It should be limited to those areas that are impacted by the loss of its Transmission, generation, or Load within its Transmission Operator Area. However, the SDT has modified the requirement based on other comments to be consistent with other standards See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
The SDT disagrees that this requirement should only apply to planned outages. If a Balancing Authority's or Transmission Operator's ICCP connection experiences an unexpected outage, they absolutely should be required to notify the other impacted entities. No change made. The SDT notes that there are slight differences between proposed TOP-001-3 Requirements R16 and R17 and the comparable IRO requirement and will make corresponding changes to align the requirements. The core purpose of the requirements which is the System Operator shall have approval authority of monitoring and analysis capabilities is not different. See summary consideration for revision. The SDT does not believe that additional clarification is needed to indicate that the Reliability Coordinator has authority over the Transmission Operator and Balancing Authority and can override their decision to approve outages of their capabilities. The Reliability Coordinator already has the authority to issue directives to these entities. No change made. The SDT agrees that derived limits can be made more specific and has modified the language of the requirement. See summary consideration for revision.		
Rayburn Country Electric Cooperative	No	I believe clarity and efficiency could be achieved by combining IRO-001-4 and TOP-001-3.Both Standards are intended to insure reliability of the interconnection. The IRO standards family itself is "Interconnection Reliability Operations and Coordination" and the purpose statement for TOP-001-3 is "To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences." The strategy could be accomplished by defining the responsibilities by two groups, those that have the authority to deliver an Operating Instruction and the second group as those who need to receive and act on an Operating Instruction. This would allow 6 requirements in my example to follow, to be condensed into 2 requirements. Delivering Entity Any one of the following functions: o Reliability Coordinator, o Balancing Authority, o Transmission Operator Receiving Entity Any one of the following functions: o Balancing Authority, o Transmission Operator, o Transmission Service Provider, o Generator Operator, o Load Serving Entity o Distribution Provider R2 Receiving Entity shall comply with the Delivering Entities Operating Instructions unless compliance with the Operating Instructions cannot be

Organization	Yes or No	Question 7 Comment
		physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. R3 Receiving Entity shall inform the Delivering Entity of its inability to perform the Operating Instruction issued by its Delivering Entity in Requirement R2 citing one of the specific reasons shown in Requirement R2.
Response: The SDT appreciates your creative approach to consolidating and simplifying requirements but believes all of the requirements are necessary and must be separate to reflect the operational hierarchical structure. For instance, Requirement R3 does not apply to a Transmission Operator because a Transmission Operator cannot issue operating instructions to another Transmission Operator. Requirement R5 is similar in that a Balancing Authority cannot issue Operating Instructions to other Balancing Authorities. However, a Reliability Coordinator can issue Operating Instructions to both. Combining the requirements and respecting this operational hierarchy would make the requirements quite cumbersome. In addition, this project inherited the scope of Projects 2006-06 and 2007-03 which indicated industry preferences for keeping the functions separate. No change made.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that some of the items in the proposed definition of Real-time Assessment are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations.” These are encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances. CenterPoint Energy believes the proposed language in R1, “...shall act, or direct others...” brings in new compliance concerns that were not present in the previous versions of TOP-001, R1. CenterPoint Energy recommends returning to the language in previous versions stating, “Each Transmission Operator shall have the responsibility and clear decision making authority to take whatever actions are needed to ensure reliability...” If the SDT agrees with this approach, CenterPoint Energy recommends conforming changes to TOP-001-3 R2 and IRO-001-4 R1 for the Balancing Authority and Reliability Coordinator’s responsibility, respectively.

Organization	Yes or No	Question 7 Comment
		CenterPoint Energy believes inconsistencies exist between R1 and R3. R1 states, "Each Transmission Operator shall act, or direct others within its Transmission Operator Area to act by issuing Operating Instructions..." A NERC defined Transmission Operator Area is the collection of Transmission assets over which the Transmission Operator is responsible for operating. R3 states, "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s)..." BAs, GOPs, DPs, and LSEs do not fall into a Transmission Operator's Transmission Operator Area as defined. CenterPoint Energy recommends the SDT review the language in R1 and R3 to determine if any modifications are required to remedy this inconsistency. CenterPoint Energy believes R7 is redundant with issuing and following Operating Instructions as described in TOP-001-3 R1 and IRO-001-4 R1. If assistance is needed under emergency or anticipated emergency conditions, the Transmission Operator or the Reliability Coordinator will issue an Operating Instruction as described in TOP-001-3 R1 or IRO-001-4 R1, respectively. CenterPoint Energy recommends deleting this Requirement. CenterPoint Energy believes R10 is vague in its expectation of monitoring Facilities of neighboring Transmission Operator Areas to maintain reliability. CenterPoint Energy believes it is the Reliability Coordinator's responsibility to monitor and address seams issues that may extend from one Transmission Operator Area to another Transmission Operator Area. CenterPoint Energy recommends the following change to the language of the Requirement or reassigning the Requirement to the Reliability Coordinator: R10. Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area.
Response: The SDT does not believe that the items cited are redundant or could cause confusion. No change made.		

Organization	Yes or No	Question 7 Comment
The SDT disagrees that identified phase angle limitations are not applicable in all regions and that they should be covered under a regional variance. While some regions may not have any specific issues, the possibility does exist for them to be an issue or they could develop at a later date. If an entity does not have such issues, they will not be identified and subject to the definition. No change made. The SDT agrees that the definition of Transmission Operator Area could be interpreted to exclude Load-Serving Entities and Distribution Providers. The SDT has modified the requirement to address comments. See summary consideration for revision. The SDT disagrees that Requirement R7 is redundant with other requirements in this standard and unneeded. Requirement R7 differs from Requirement R3 in that it does not allow a Transmission Operator to Transmission Operator directive. Requirement R5 is not relevant since it involving following a Balancing Authority's directives and Requirement R7 involves assisting a Transmission Operator so they are initiated by two different entity types. The SDT agrees that Requirement R7 could be viewed as partially redundant with Requirement R3 for a Balancing Authority complying with a Transmission Operator issued directive and will remove the Balancing Authority from the requirement. The SDT has made other modifications to the requirement based on other comments as well. See summary consideration for revision. The SDT disagrees that the Transmission Operator should only monitor Facilities within it Transmission Operator Area. Facilities outside of its Transmission Operator Area impact the reliability of its area and the Transmission Operator should be monitoring these facilities. However, the SDT has modified the requirement to provide some additional clarification regarding monitoring into a neighboring Transmission Operators Area. See summary consideration for revision.		
Exelon Companies	No	Exelon agrees with all but one aspect of the proposed standard.R18. Each Transmission Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting parameter in instances where there is a difference in derived limits. R18 previously included other entities as identified in the Rational including the LSE, PSE, DP and TSP. The rational statement says deleting these entities is being done "as those entities will receive instructions on limits from the responsible entities cited in the requirement". Exelon Generation believes the GOP belongs in the same category as the above deleted entities for this requirement. We note that "derived limit" is an undefined term. It may be a term of art in the TOP lexicon but it is not commonly used or understood by GOP's. In dozens of audits, no auditor has been able to tell us (Exelon Generation Company, Nuclear and Fossil)

Organization	Yes or No	Question 7 Comment
		what this means with respect to a generator operator. The TOP may derive limits on the transmission system but in our experience the GOP does not. The GOP provides facility status information, GSU limits etc. that the TOP can use to calculate /model / derive the limits on the transmission system. Providing facility status and following Directives and Operating Instructions is a GOP responsibility, deriving limits implies information about a dynamic system being modeled and evaluated so as to determine the limits to transmission system operation which is a TOP and or a RC responsibility. As background, we point out that the pre version 0 NERC Operating Guide 200 from which this requirement appears to come did not include the GOP and the ver. 0 standard IRO-005 R13 did not include the GOP in the applicability for this standard (all above Rational 18 deleted entities and GOPs were added in IRO-005 R13 text but not included in the applicability for the standard). Changes to the applicability section of IRO-005 that included these entities was later added via an errata. This issue and a cogent FERC response to it was identified in Order 693944. TAPS raises an issue with Requirement R13 that states in part "[i]n instances where there is a difference in derived limits,...Load-Serving Entities...shall always operate the Bulk Electric System to the most limiting parameter." TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load.950. We [FERC] do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.

Response: The SDT has modified the requirement to reflect that derived limits are SOLs. The SDT agrees that the Generator Operator should not be included for the purpose of SOLs because they will have no knowledge of these limits. Furthermore, the

Organization	Yes or No	Question 7 Comment
Transmission Operator and Reliability Coordinator could simply direct the Generator Operator to adjust unit outputs to operate within established SOLs. See summary consideration for revision.		
City of Garland	No	Requirement 1 Concern # 1The volume of applicable Reliability Standards already requires action or directing others to act. In an audit situation, the NERC auditor cannot find a possible violation for failing to “act or direct others to act” without also identifying which Requirement in which NERC standard that required action - therefore, there is already an existing requirement to act or direct others to act without this proposed requirement. Recommendation # 1Replace this proposed requirement with the existing requirements concerning authority. Concern # 2The “act, or direct others to act” is executed by experienced, NERC Certified Personnel who make decisions in real-time based on the information available at that time. To continuously compile supporting information to support each decision / action taken by experienced, NERC Certified Personnel for an audit situation will be time consuming, labor intensive and will require voluminous data storage. Also, unless there is some event that triggers an event analysis, how is the auditor going to determine the “when”, “what” and “how” in a normal audit months or years later to decide whether the entity is in violation. Sometimes the correct action to take is “no action” based on the information available at the time. Recommendation # 2 Replace this proposed requirement with the existing requirements concerning authority. Requirement 2 Same concerns as listed under question 7 - Requirement 1 Requirement 10 Concern: “shall monitor Facilities within its TOP Area and neighboring TOP Areas” - The “and neighboring TOP Areas” is too vague and too open to interpretation - should not be left to an auditor’s opinion during an audit situation to determines what facilities and how “deep” into neighboring TOP Areas must be monitored to be compliant. Recommendation: delete “and neighboring TOP Areas” Requirement 13 Concern 1There is no provision to allow for any number of reasons why a Real-time Assessment might not be completed on a 30 minute cycle without it

Organization	Yes or No	Question 7 Comment
		being a violation - any way one looks at it, “life is not perfect” and an entity (the TOP) should not be fined or spend financial / personnel resources to work through a potential violation every time a Real-time Assessment fails to complete. Concern 2 There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability - all TOPs are not created equal.

Response: The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made.

The SDT has modified data retention for this requirement to minimize the burden will be associated with this requirement. See summary consideration for revision.

The SDT disagrees that the Transmission Operator should only monitor Facilities within its Transmission Operator Area. Facilities outside of its Transmission Operator Area impact its reliability and the Transmission Operator should be monitoring these facilities. However, the SDT has modified the requirement to provide some additional clarification regarding monitoring into a neighboring Transmission Operators Area. See summary consideration for revision.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.
The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Organization	Yes or No	Question 7 Comment
The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT was very intentional in writing the definition of Real-time Assessment and Requirement R13 to allow for third-party services. Thus, Requirement R13 is not intended to require a Transmission Operator to have state estimation and Real-time Contingency analysis. Other methods may be relied upon included utilizing the Transmission Operator's Reliability Coordinators results. The SDT has modified Requirement R13 and the definition of Real-time Assessment to further clarify this understanding. Smaller entities today must have a way to assess their system in Real-time, whether this is relying on operational planning studies, system knowledge, its own Real-time Contingency analysis or possibly its Reliability Coordinator's. Otherwise, how can a small entity determine it is operating within first Contingency? See summary consideration for revision.		
Ingleside Cogeneration LP	No	ICLP believes the changes made to TOP-001-3 have reintroduced enormous administrative overhead into our compliance approach for Operating Instructions. That issue was resolved in COM-002-4 by focusing on the training of GOP front-line operators who receive Operating Instructions - not their actual execution. This was a necessary step because the range of communications that constitute an Operating Instruction is very broad, and it is unreasonable to expect that every one of them will be perfectly executed and documented to the liking of an audit team. The problem is that there are two distinct categories of interest. The first are those which are issued as an urgent action, and which are really the target of TOP-001-3. It is appropriate to expect that those Operating Instructions issued during Emergencies and near-Emergencies should be handled in a zero-tolerance manner. However, those issued in the normal course of business - by far the larger category - must be excluded. TOP-

Organization	Yes or No	Question 7 Comment
		001-4 R1 and R2 provides no limitations on applicable Operating Instructions. This ambiguity can be resolved in different ways. The drafting team could add language back to Requirements R1 and R2 specifically limiting their applicability to a set of defined circumstances. A better method may be to require the TOP or the BA to identify the Operating Instruction as "critical" to the recipient in order to heighten awareness and ensure compliance. Furthermore, ICLP believes that a qualifier must be added to R3 and R5 for the Operating Instruction recipient to notify the issuer "upon recognition" of its ability to perform it. This language would account for situations where the inability to act is recognized sometime after the instruction is issued. This happens in real-time and it is not appropriate to penalize an entity who initially believes that they can execute a critical Operating Instruction in good faith - but finds out later they cannot. Lastly, ICLP does not agree with the intent and language of Requirement R18. This poorly defined requirement has been transferred from IRO-005 - and has been inconsistently applied by CEAs. R18 leaves it to the GOP to operate to someone's most "limiting parameter" if there is a conflict with someone else's "derived limits". This seems to infer those transmission Facility Ratings, SOLs, or IROLs maintained by the RC and TOP - parameters which GOPs do not monitor. Those difference should be resolved between TOPs and RCs, who then must inform the GOP what the proper limits are.
Response: While the SDT agrees that Operating Instructions issued during Emergencies are very important, failure to follow an Operating Instruction issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. No change made. The SDT does not believe the proposed modifications to Requirements R3 and R5 provide any clarification. The requirements as written require the responsible entity to comply with the Operating Instruction unless it can't for one of the allowed reasons. Then, it must notify the issuer. This could only occur once they recognize it. No change made. The SDT agrees that the requirement should not apply to Generator Operators and has modified the requirement. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. Real-time Assessment definition - ATC suggests the definition be reworded as follows for added clarity. “An evaluation of system conditions using Real-time data to assess contingency conditions, limited to the single Contingency loss of a generator, line, transformer or shunt device and multiple outages as specified by its RC, to assess potential operating conditions.” Otherwise, ATC suggests the following changes to the definition: Modify the first sentence of the definition by adding the word “single” to read, “An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) operating conditions.” Otherwise, ATC suggests adding a sentence to the proposed definition to read, “Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator.” b. R1 - For clarity, ATC recommends that Requirement R1 be modified to define “others” as “DP(s), LSE(s), BA(s) and GOP(s).” c R2, R11, R17 - N/A d. R3 - ATC agrees with the proposed TOP-001-3 Requirement R3. e. R4 - ATC agrees with the proposed TOP-001-3 Requirement R4. f. R5 - ATC agrees with the proposed TOP-001-3 Requirement R5. g. R6 - ATC agrees with the proposed TOP-001-3 Requirement R6. h. R7 - ATC agrees with the proposed TOP-001-3 Requirement R7. i. R8 - ATC has no comment regarding Requirement R8. j. R9 - Notification of telemetering and telecommunication outages. The SW Outage Report recommendation is specific to reporting technical issues with their contingency analysis capabilities after the functionality is lost. Therefore, ATC recommends the requirement should be revised as follows to only address forced or unexpected outages. “R9. Each Balancing Authority and Transmission Operator shall

Organization	Yes or No	Question 7 Comment
		notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” k. R10 - ATC sees Requirement R10 as ambiguous regarding what is being monitored. It is unclear if the TOP is to monitor topology changes, analog values for violation, and/or model neighboring TOP contingencies in its Real-time Assessments for the neighboring TOP system. In addition, the current wording does not clearly state which sub-100 kV facilities are to be monitored (i.e., its TOP area or the neighboring TOP area). ATC recommends splitting the requirement into two parts to address these issues. ATC recommends rewording Requirement R10 as follows:”R10. Each Transmission Operator shall monitor BES Facilities and the status of Special Protection Systems within its Transmission Operator Area needed to maintain reliability within its Transmission Operator Area, including non-BES Facilities needed to maintain reliability.” l. ATC recommends Requirement R10.1 be added prepared as follows: “R10.1. Each TOP shall monitor system topology changes within neighboring Transmission Operator Areas, including non-BES Facilities, to maintain reliability within its Transmission Operator Area.” m. R12 - ATC agrees with the proposed TOP-001-3 Requirement R12. n. R13 - ATC provides the following suggestions regarding Requirement R13. Perform Real-time Assessment at least once every 30 minutes. Paragraphs 55 and 60 (of the NOPR) do not specifically require a timeframe for monitoring and assessment capabilities. Therefore, it is recommended to remove the Real-time Assessment at least once every 30 minute requirement. In addition, NERC has already developed the ERO Event Analysis Process Document to address reporting the loss of monitoring or control at control centers (which includes unacceptable State Estimator or Contingency Analysis solutions) and should provide adequate assurance of industry performance related to control center situational awareness tools. If the SDT retains

Organization	Yes or No	Question 7 Comment
		the requirement, ATC recommends developing a performance-based requirement as opposed to a single time limit in which the Transmission Operator would be required to report for every excursion. Example - CPS1 / CPS2 BA performance metrics. o. R14 - If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, ATC feels that the language in Requirement R14 should be improved modified by removing some redundancy and adding clarity. ATC suggests the removal of "Real-time monitoring" from the proposed requirement since the "Real-time Assessment" definition already requires assessing existing operating conditions. In addition, ATC suggests the addition of "within its Transmission Operator Area" to R14 to provide clarity and be consistent with the language proposed for TOP-002-4. ATC suggests the language of Requirement R14 read as follows:"R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance within its Transmission Operator Area identified as part of its Real-time Assessment." p. R15 - ATC agrees with the proposed TOP-001-3 Requirement R15. However, ATC suggests development of a similar requirement applicable to Interconnection Reliability Operating Limits (IROLs). q. R16 - If ATC's first proposal for changing the definition of "Real-Time Assessment" is not implemented, the language in Requirement R16 should be modified by removing some redundancy and adding clarity. ATC suggests the removal of "monitoring" from the proposed Requirement R14 since the "Real-time Assessment" definition already requires assessing existing operating conditions. ATC also suggests the addition of "within its Transmission Operator Area" to R16 for added clarity. ATC suggests the requirement be reworded as:"R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages of its own Real-time Assessment capabilities within its Transmission Operator Area." r. R18 - To improve clarity and be consistent with proposed definitions, ATC suggests revising Requirement R18 by replacing the term "derived operating limits" as indicated in the following revision of the requirement:"R18. Each Transmission

Organization	Yes or No	Question 7 Comment
		Operator, Balancing Authority, and Generator Operator shall always operate to the most limiting real-time (pre-Contingency) or potential (post-Contingency) operating condition in instances where there is a difference in SOLs or Real-time Assessments.”

Response: a. The SDT does not believe that the proposed changes provides any additional clarification and actually may create confusion by conflicting with approved FAC-011 Requirement R3, Part3.3 which already requires the Reliability Coordinator to identify which multiple Contingencies are applicable to the SOL methodology. Thus, all Contingencies would be single Contingencies unless a multiple Contingency is identified by the Reliability Coordinator’s SOL methodology. No change made.

b. The SDT does not believe identifying others in Requirement R1 is necessary as “others” would be those obligated to respond in Requirement R3. No change made.

c. – i. The SDT thanks you for your agreement.

j. The SDT disagrees that notification for monitoring capability outages should only occur with forced or unplanned outages. Regardless of the reason for the outage, other entities need to know about the outage so they can increase their vigilance in monitoring. The Reliability Coordinator in particular would then monitor the Transmission Operator or Balancing Authority with the monitoring capability outage more closely. The SDT does agree with removing “negatively” from the requirement. No additional changes made. See summary consideration for revision.

k. and l. The SDT disagrees that Requirement R10 should be split into two requirements but has modified the requirement for clarity. See summary consideration for revision.

m. Thank you for your agreement.

n. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time

Organization	Yes or No	Question 7 Comment
Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. o. The SDT disagrees and believes that Real-time monitoring can find violations. No change made.. p. The SDT thanks you for your agreement with Requirement R15. However, the SDT does not believe that a similar IROL requirement is necessary for the Transmission Operator. There is a parallel IROL requirement that is applicable to the Reliability Coordinator. Responsibilities for IROLs and SOLs have been divided in the standards with the Reliability Coordinator having primary IROL responsibility and the Transmission Operator having primary SOL responsibility. No change made. q. The SDT does not believe the proposed addition to Requirement R16 provides any additional clarity. The Transmission Operator could not approve an outage of its neighbors monitoring capability, it could only approve an outage of its own capability. While its neighboring Transmission Operator may approve an outage of its own monitoring and Real-time Assessment capabilities and these outages may impact other Transmission Operators, a Transmission Operator still cannot approve its neighbor’s outages. No change made. r. The SDT has clarified Requirement R18. Derived limits are SOLs. See summary consideration for revision.		

Organization	Yes or No	Question 7 Comment
American Electric Power	No	R8: Needs additional clarity and consistency with other requirements. A TOP is able to communicate any emergencies they see/foresee in their system and communicate these issues to the RC and entities known to be directly-impacted. The RC would have the wide-area view necessary to determine any impacts to other BAs or TOPs. However, a TOP would have limited ability to know if they're creating any impact regarding other BAs or TOPs that aren't interconnected with them. The standard should be changed to require the RC, not the TOP, provide such communication. R9: The requirement needs to specify which "negatively impacted interconnected NERC registered entities" need to be notified in order to be consistent with R8 and other requirements. R10: It is not clear exactly which sub-100 KV Facilities need to be monitored by the TOP. In addition, the TOP is in the best position to make this determination. The requirement should be changed to allow the TOP flexibility to identify which facilities are to be monitored.
Response: The SDT agrees that the Transmission Operator may not know the full impact of its operations which is the reason there are Reliability Coordinators. However, the Transmission Operator should know if it impacts the Balancing Authority. The requirement has been modified accordingly. See summary consideration for revision. The SDT disagrees and does not believe that the suggested change adds clarity. No change made. Requirement R10 was always intended for the Transmission Operator to make the determination of which of its neighboring Transmission Operator's Facilities it needs to monitor. The requirement has been modified to provide additional clarification. See summary consideration for revision.		
NIPSCO	No	1. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard. 2. In R8 NIPSCO would like the term "emergency" defined. Is an "emergency" the same as a SOL exceedance or is it a SOL or IROL violation?

Organization	Yes or No	Question 7 Comment
		3. R10 requires that TOPs monitor adjacent TOP facilities as "needed to maintain reliability." This term is vague and needs defined parameters or criteria. 4. The data retention period for R13 is far too long, as the RTCA files are quite large (current calendar year + previous calendar year).
Response: (1) The SDT understands how one could view Requirements R16 and R17 as outage coordination. However, the SDT believes the outage coordination standard deals with BES Elements while Requirements R16 and R17 pertain to monitoring and analysis capabilities which more appropriately belong in a standard dealing with monitoring and operating in Real-time which is proposed TOP-001-3. No change made. (2) Emergency is already a NERC defined term. An SOL exceedance could qualify as an Emergency. An IROL violation or exceedance certainly would. However, other events such as a significant equipment overload (i.e., one that risks immediate failure of the equipment) could be an Emergency as well. Please refer to the definition. No change made. (3) The SDT has modified Requirement R10 to better reflect that it is only those neighboring Transmission Operator Facilities that impacts its own Transmission Operator Area. See summary consideration for revision. (4) Requirement R13 does not require RTCA. However, recognizing that many entities might utilize RTCA to meet the requirement, the SDT agrees and has modified the data retention to 30 days. See summary consideration for revision.		
Idaho Power	No	I do not agree with the rationale for the change in terms. There need to be something to differentiate between a communications that must be followed to alleviate existing or potential conditions to preserve system reliability. Operating instructions should be normal communication between a System Operator and field personnel during routine switching or system adjustments. A Reliability Directive is an order to do a task without hesitation unless it would violate safety, equipment, regulatory or statutory requirements. As currently written the standard would seem to apply to anything the RC requested a TOP to do. Reliability Directive is in the NERC glossary of terms currently.

Organization	Yes or No	Question 7 Comment
		The first sentence in R1 notes this when it states "or DIRECTS others". This change will create confusion resulting in adverse reliability impacts and compliance violations. I'm not clear on what R10 requires. Would we be required to monitor all our adjacent TOP's SPS and communication systems, facilities that the SPS monitored or just request a status point via ICCP form the adjacent? Needs to be clearer on what the requirement expects to be monitored.
Response: While the SDT agrees that Operating Instructions issued during Emergencies are very important, failure to follow an Operating Instruction issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. The SDT disagrees that the Operating Instruction would apply to anything the Reliability Coordinator would ask a Transmission Operator to do. For instance, if a Reliability Coordinator requested the Transmission Operator to determine how quickly they could return a line to service that was out on maintenance, this would not be an Operating Instruction. While we agree Reliability Directive is in the NERC Glossary, it was never approved by FERC. No change made. The SDT is confused by the comment regarding "or DIRECTS others" in Requirement R1 and how it will create confusion resulting in Adverse Reliability Impacts and compliance violations. Transmission Operators provide instructions to "others" all the time. For example, when it issues a switching instruction, it communicates this to field personnel or possibly to a Distribution Provider that is connected to its transmission line. Without additional specificity, the SDT has no choice but to leave the requirement unchanged. The Transmission Operator would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to Requirement R10 to provide clarification. See summary consideration for revision.		
David Kiguel	No	R7: How will the entity that requested assistance demonstrate and how will the entity whose assistance was requested verify that the requesting entity has implemented its emergency procedures? R10: Requires TOP to monitor facilities in neighboring TOP Areas, i.e. outside its own area of responsibility.

Organization	Yes or No	Question 7 Comment
		R11: How will the BA monitor SPS status i.e. who provides the information? Better to assign requirement action to the entity providing the information to the BA. This seems to be covered by TOP-003-3 R4, i.e. no need to repeat here.
Response: The requesting entity can simply notify the recipient that it implemented its emergency procedures. The recipient will have to depend on this simple notification or risk a compliance violation for not providing assistance. The observation on Requirement R10 is correct. The Transmission Operator needs to monitor only those the Facilities in its neighboring Transmission Operator Areas that impacts its own reliability. The requirement has been updated to reflect this. See summary consideration for revision. Proposed TOP-003-3 Requirement R4 provides a mechanism to receive the data on SPS status. Requirement R11 requires the Balancing Authority to actually monitor the status. No change made.		
Austin Energy	No	City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments on R1: (1) AE does not agree with the change to R1, which removes the “responsibility and clear decision-making authority” language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. System Operators are familiar with the NERC Reliability Standards, but they are not as well versed in the specifics of FERC Orders, such as FERC Order 693a, paragraph 112. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to “act, or direct others ... to act” while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. AE recommends combining the old and new R1 language to state “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed, including issuing Operating Instructions, to address its reliability functions within its Transmission Operator Area.” (2) AE does not agree with R10, which requires monitoring “neighboring Transmission Operator Areas to maintain reliability.” Without additional guidance, many TOPs will

Organization	Yes or No	Question 7 Comment
		be left with a requirement to monitor its neighbors' entire systems. The role of coordinating reliability is that of the Reliability Coordinator, as agreed by the SDT on the project's 6/12/14 webinar. During the webinar, the SDT stated the TOP should be aware of seams but it is the RC that has ultimate responsibility to ensure reliability across the seams. AE respectfully requests the SDT to review this issue further and refine the requirements accordingly. (3) AE believes R7 is not necessary as written. Assistance requested from one TOP to another is just that, a request. If it becomes an issue of reliability, the TOP would need to involve the RC who has other requirements in place allowing the RC to issue an Operating Instruction to the necessary TOP(s). AE requests the SDT remove R7 from TOP-001-3.
Response: (1) The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made. (2) The Transmission Operator would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to requirement R10 to provide clarification. See summary consideration for revision. (3) The SDT disagrees that Requirement R7 is not necessary. Requirement R7 obligates Transmission Operators to work together to provide assistance during Emergencies. While the Reliability Coordinator likely will be involved, a directive from a Reliability Coordinator should not be necessary for a Transmission Operator to begin assisting another Transmission Operator. Some clarifying changes have been made to the requirement based on comments from others. See summary consideration for revision.		
Ameren	No	R3 - We operate as both a TO and BA. This change isn't really negative, but it always seems strange to us when we say that as a BA we comply with instructions issued by the TO, which is us. We believe that NERC should have clarifying language that it is more intuitive for entities that operate as a combined BA/TO, so that requirements that state that the BA follows instructions/directives from the TO (or vice versa) are not applicable. R4 - We are concerned because "BA" is in the list of entities required to follow directives issued by the TO. Our current RSAW says this is NA since it is only for DP's

Organization	Yes or No	Question 7 Comment
		and LSE's. Under the proposed draft with the BA listed in the requirement, we now have to state that as a BA, we follow directives given by the TO, which is also us, and in our opinion this doesn't make sense for the way we are organized. R6 - See my comments about BA's following instructions/directives from TO's as stated above. It also looks like they have new requirements stating that TO's will follow instructions issued by its BA. As stated earlier we have the same sort of comments, as for us, we are one in the same. R13 - We ask for clarification; does the drafting team mean running something automatically like the RTCA, this, conceptually, is OK, since we run it every 2 minutes. However if the drafting team means something else, we need to object, as we simply don't have manpower to perform manual studies every 30 minutes. The issue is, assuming the RTCA; would it be a reportable violation if the RTCA program goes down for longer than 30 minutes? We believe it would be a burden to ask entities to track and self-report instances where RTCA was down for 30 minutes or longer.

Response: The SDT appreciates the concern that faces many entities that operate as both a Balancing Authority and Transmission Operator. However, NERC decided to write the reliability standards requirements based on the functional model. These are two separate functional entities that can and are operated by separate companies in many areas. The SDT believes this is essentially a compliance monitoring issue. The SDT encourages you to work with your regional entity to address it. No change made.

The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

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· **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of “Real Time Assessment” does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking “alternative actions” and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator’s Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Consumers Energy	No	I am opposed to replacement of Reliability Directive with Operating Instruction. Reliability Directive is a much stronger term than Operating Instruction, and should be used in this context. R5 and R6 - I generally agree, except for Reliability Directive vs. Operating Instruction as noted above. This should be Reliability Directive. R9 - I am concerned about the general treatment of outages discussed in the requirement. It is not uncommon to experience frequent brief outages - requirement should have a “of duration greater than <some value, perhaps 15 minutes>“. R10 - Individual TOPs may not be able to obtain monitoring access to adjacent TOP areas - this could create a compliance risk outside the entity’s control.
Response: Failure to follow an Operating Instructions issued during normal operating conditions can and has led to actual Emergencies. This was the case in the September 2011 Southwest Outage. Thus, the SDT believes that the standard should apply to Operating Instructions and not just Reliability Directives. Furthermore, this make the standard consistent with proposed COM-002-4. No change made.		

Organization	Yes or No	Question 7 Comment
The SDT disagrees that a timing factor is needed in the requirement and believes that placing such a factor in the requirement may actually be detrimental to reliability. No change made. The SDT is not aware of any situations in which a Transmission Operator has not been able to gain data and information from neighboring Transmission Operators. No change made.		
Liberty Electric Power, LLC	No	See comment provided to the similar IRO standard.
Response: See response to IRO comments.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 states:"R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment..."In response to R9, Oncor recommends that the requirement make it mandatory for RC's and TOP's to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it is necessary to notify registered entities that do not have reliability control functions to the BES. R10 as proposed requires each "Transmission Operator monitor facilities in neighboring Transmission Operator Areas in order to maintain reliability within its Transmission Operator Area". The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor the facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. Oncor requests R10 be reworded to provide flexibility for region structure. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple

Organization	Yes or No	Question 7 Comment
		TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit. Proposed R13 states: "Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes." Oncor considers Real-time Assessments to be a Reliability Coordinator function. In the ERCOT region, Transmission Operators do not have the wide area overview that is required to perform the task. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator creates added expense and contributes no added reliability to the BES. Oncor requests R13 be reworded to provide flexibility for region structure.
Response: The SDT disagrees that the suggested change adds clarity. No change made. Data communications between the Transmission Operator, Balancing Authority, and Reliability Coordinator are bi-directional. Transmission Operators should work with the Reliability Coordinator to put processes in place to receive the external data required for reliability. The SDT does not believe this should be a financial burden. No change made. The T_v of an IROL is determined according to the Reliability Coordinator SOL methodology per approved FAC-014-2 Requirement R1. No change made. While the Reliability Coordinator does have responsibilities to monitor and assess reliability for its Wide Area, this does not remove the responsibility for the Transmission Operator to monitor and maintain reliability in its own Transmission Operator Area. No change made.		
ITC	No	ITC has concerns with the definition of "Real Time Assessment". Real time assessment is typically conducted by tools such as State Estimator and Contingency Analysis. Inclusion of known protection system and special protection system status or degradation is not practical or possible in real time simulations as these simulations are steady state analysis while studying protection system degradation requires a dynamic analysis. As suggested under comments on Operational Planning Analysis Definition, protection system degradations are studied when the outages on

Organization	Yes or No	Question 7 Comment
		protection system or associated elements are planned. Including this analysis in real time assessment may require dynamic simulations every thirty minutes which is not practically possible and provides no additional benefits. ITC supports that unplanned protection system outages impacting BES reliability shall be evaluated and appropriate action should be taken however conducting this evaluation as part of real time assessment shall not be required. ITC recommends modifying this definition by removing protection system and special protection system status or degradation. Regarding R10, ITC recommends adding clarification to this requirement clearly outlining that it is up to the TO to determine which external facilities to monitor based on impact to their internal system. ITC also recommends removing sub-100 kV language as a sub 100 kV element needed to maintain reliability of the system should already be designated as part of BES. In reference to R14, ITC would like clarification from the SDT as to whether the standard will include the methodology/examples listed in the SOL Exceedance White Paper.
Response: The SDT does not intend for a Real-time Assessment to include dynamic analysis. However, the SDT believes that the evaluation of Protection System outages and SPS outages can and should be assessed in steady state analysis. As an example, Contingencies could be modified to reflect an outage of the Protection System that may cause more Facilities to be cleared during a fault. No change made. The SDT agrees with your assessment and has modified Requirement R10 accordingly. See summary consideration for revision. The whitepaper will be appended to the standards.		
Hydro One	No	R-10 requires TOPs to monitor facilities in neighboring TOP areas and is an overlap of an RC wide area review responsibility.
Response: The SDT disagrees that monitoring facilities in neighboring Transmission Operator Areas is an overlap of the Reliability Coordinator Wide Area responsibility and believes it is necessary for Transmission Operator reliability. However, the SDT did modify		

Organization	Yes or No	Question 7 Comment
the requirement to reflect that it only needs to monitor the Facilities in neighboring Transmission Operator's Areas necessary to maintain reliability in its own Transmission Operator Area. See summary consideration for revision.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State believes R10 is confusing as it is written. We believe the portion stating "...including sub-100kV facilities needed to maintain reliability..." is redundant as "Facilities" is a defined term that includes any element that is part of the BES. With the new BES definition, elements may be included through the Rules of Procedure exception process if they are important to the reliability of the BES.
Response: The SDT has modified the requirement for clarity based on comments. See summary consideration for revision.		
Independent Electricity System Operator	No	We do not agree with Requirements R2, R5, R6, R7, R9, R11, R17 and R18. Requirement R2 stipulates that "Each Balancing Authority shall act, or direct others within its Balancing Authority Area to act by issuing Operating Instructions, to address its reliability functions within its Balancing Authority Area." This requirement seems out of place. Further it doesn't provide any incremental value since it is written at too high of a level and would be difficult to measure. The purpose of the standard is to ensure transmission operating reliability, not resource adequacy, balancing capability or frequency performance. The BA is not required to have any transmission information, and it does not have any sole responsibilities in ensuring transmission reliability other than responding to instructions by its TOP or RC to manage resource-demand-interchange balance or interchange schedules to assist in mitigating transmission constraints. With respect to implementing the IERP's and OC's recommendation to ensure BA has the authority to act or direct others to act, any such requirements (to maintain resource-demand-interchange balance or meet frequency performance targets) should be placed in the BAL standards or the EOP standards, but not in a TOP standard. We suggest R2 be removed. In addition, Requirements R5 and R6 should be removed as well. For Requirement R7, we do not see the need to include the Balancing Authority since it is supposed to comply with the Operating Instructions of its Transmission Operator

Organization	Yes or No	Question 7 Comment
		(in R3). We believe the proposed R7 is a revised version of R4 of TOP-001-2, which was approved by the NERC BoT in May 2012. Requirement R4 in TOP-001-2 did not include the BA as a responsible entity. We suggest to remove the BA from R7. Requirement R9 stipulates that: “Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” The last part appears to be unclear as the “affected entities” can be interpreted as any two entities not including the one that is experiencing or anticipating outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. In that case, the entity that is held responsible for notifying others of its existing or anticipated outages will have no knowledge if the “associated communication channels between affected entities” will have an outage and if so, whether such an outage will negatively affect others. We suggest the last part be revised to “between it and the affected entities”. Requirement R11 is out of place for the similar reasons indicated for R2, above. In addition the requirement seems inappropriate for the BA as it assigns transmission accountabilities which are not required in the Functional Model. We suggest removing this requirement. Requirement R17 is out of place for the similar reasons indicated for R2 and R11. We suggest moving this requirement to the appropriate BAL or EOP standard. Requirement R18 should not include the Balancing Authority since it does not operate any Facilities for which there are limits derived by more than one entity, unlike its TOP or RC counterpart.

Organization	Yes or No	Question 7 Comment
Response: The SDT ultimately agrees that Requirements R2, R5, R6, R11, and R17 belong in the BAL standards but there is no current active project that with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BA standards at a later date. No change made. The SDT agrees and has removed Balancing Authority from Requirement R7. See summary consideration for revision. The SDT has modified the requirement to provide additional clarity based on comments. See summary consideration for revision. The SDT disagrees that a Balancing Authority should not be included in Requirement R18. While a Balancing Authority may not derive limits, it certainly does operate to them in certain cases. No change made.		
INDN - Independence Power & Light	No	INDN supports the comments submitted by Southwest Power Pool. In addition R10 does not provide enough detail as to what the TOP's responsibility is. How far into a neighbor's facility are we required to monitor? At some point this should become the responsibility of the Reliability Coordinator, who has a much better regional view than individual TOPs. R13 attempts to make a "one size fits all" solution for performing Real Time Assessments. We believe this is too prescriptive and does not reflect a realistic approach to operations in some environments. For a TOP with no identified IROL or an entity that typically operates at low load levels it may not be necessary to perform a full assessment every 30 minutes. Small operations with minimal staffing will be unnecessarily burdened to perform, review and document assessments that add little or no Reliability benefit in these circumstances. A better approach may be to establish a threshold for system capacity or rate-of-change that would then trigger the 30 minute interval.
Response: The TOP would be required to ultimately monitor what impacts its Transmission Operator Area reliability. Changes have been made to Requirement R10 to provide clarification. See summary consideration for revision. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the		

Organization	Yes or No	Question 7 Comment
current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Modesto Irrigation District	No	MID believes that the implementation timeline for TOP-001-3 is not adequate to handle the business changes required by R13. MID suggests two years be allowed to implement R13.
Response: The SDT disagrees with the need to extend the implementation period to 24 months for Real-time Assessments. While they may not have been explicitly required, Real-time Assessments have always been necessary for a Transmission Operator. Transmission Operators are currently required to operate within all SOLs and IROLs. How can they do this without today performing a Real-time Assessment? No change made.		

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Electric Reliability Council of Texas, Inc.	No	Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: "Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term "Operating Instruction" outside of real time.
Response: The SDT disagrees and believes that the replacement of the authority language with the action language is the correct approach. No change made. Please see our comments to IRO-008 for Requirement R14. Please see our comments to IRO-001 regarding Operating Instruction.		
California ISO	No	The wording in proposed TOP-001 requirements R1 and R2 contains the following phrase: "by issuing Operating Instructions, to address its reliability functions". The term "reliability function" is not defined in the standard or in the NERC Glossary of Terms, especially as it applies to each individual entity (i.e., - "its reliability functions") and is therefore too vague and subject to interpretation. These requirements could possibly reference "reliability-related tasks" which are required to be defined by PER-005, however this might not be inclusive enough because there might be

Organization	Yes or No	Question 7 Comment
		unanticipated situations when an Operating Instruction is necessary to maintain reliability but isn't related to a documented task. The ISO would propose changing this wording to something like "by issuing Operating Instructions, for reliability purposes" or "by issuing Operating Instructions, when necessary to maintain reliability".
Response: The SDT has modified Requirements R1 and R2 for clarity based on comments. See summary consideration for revision.		
Texas Reliability Entity	No	1) R1: The use of the defined term "Transmission Operator Area" in R1 and R10 may lead to potential conflicts and reliability gaps. Transmission Operator Area is defined in the NERC glossary as "The collection of Transmission assets over which the Transmission Operator is responsible for operating." Transmission is capitalized indicating the following NERC glossary definition, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Using these definitions in the requirements may create a reliability gap if a TOP determines that generation, LSEs or DPs are not included in the Transmission Operator Area because they don't meet the definition of Transmission. In the ERCOT region where we have had TOP entities make the argument that generation units are not in their Transmission Operator Area and therefore they were not required to monitor those facilities. Similarly, it could be argued that ERCOT as a TOP does not "operate" any transmission assets. In the ERCOT region, a Coordinated Functional Registration is required between ERCOT and 15+ utilities to clarify the responsibilities of the TOP Function. Would the SDT consider adding technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area. Clearly, R3 requires BAs, GOPs, DPs and LSEs to comply with Operating Instructions issued by its TOP but there appears to be a risk that a TOP may not issue an Operating Instruction to an entity they do not consider within their Transmission Operator Area due to the definition.

Organization	Yes or No	Question 7 Comment
		2) R4: Recommend adding the following additional language behind the sentence in R4: "The instructed Entity will inform the TOP within 30 minutes of determining that it would not be able to or failed to carry out the Operating Instruction." If an Operating Instruction cannot be followed by the instructed entity, the TOP needs to be informed of the situation in time for the TOP to react accordingly for the continued reliability of the BPS. Adding the stated time horizon will add another measure to R4. 3) R6: Recommend adding the following language at the end of the Requirement: "citing one of the specific reasons shown in Requirement R5." This will be consistent with R4 referencing R3. 4) R8: Recommend adding the following language at the end of the Requirement: "The TOP shall inform the Entities of these issues within 30 minutes of determining that its actual or expected operations that result in, or could result in, an Emergency." The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, communication of actions taken or expected actions that may result in and emergency should be communicated before that emergency occurs. As written the TOP could be compliant by informing the Entities well after the potential or actual emergency has occurred. 5) R9: Recommend adding "within 30 minutes" between "shall notify" and "its Reliability Coordinator". This will help assure that notified entities will have time to appropriately respond. The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. R9 has no stated time horizon for notification. As written the BA and TOP could be compliant by informing the RC (and other impacted interconnected entities) well after the potential or actual emergency has occurred. 6) R9: Recommend excluding "negatively" and "interconnected" and simplifying to "impacted" entities to be consistent with TOP-002-4 language. And to reflect that

Organization	Yes or No	Question 7 Comment
		entities that are not "interconnected" can be impacted by outages of the equipment mentioned in R9. 7) R15: Recommend adding "within 30 minutes of having completed actions, provided the TOP is capable of reporting the actions" between "shall" and "inform its Reliability Coordinator". The purpose of the standard is to ensure prompt action to prevent or mitigate adverse impacts to reliability. As such, the RC must have up to date information concerning actions taken within its area to perform its reliability responsibilities.
Response: (1) The SDT has modified Requirement R1 to clarify that it includes entities connected to its Transmission Operator Area. The SDT does not see a similar issue with Requirement R10 and has not modified it based on this comment. (2), (4), and (7) The SDT does not agree with adding 30 minutes to Requirements R4, R8, and R15. There are times when a 30-minute notification would be sufficient and other times it would not be (i.e., when exceeding a 15-minute limit) and could impact reliability. While adding this term would make it more measurable for compliance, it could be contrary to reliability. Each situation is unique regarding how quickly a receiving entity should notify the issue of its inability to follow an Operating Instruction but it should be quickly. No change made. (3) The SDT disagrees with the addition to Requirement R6 and actually is removing the "citing" language in Requirement R4 due to other comments. At the time an entity notifies the Transmission Operator or Balancing Authority that it cannot implement an Operating Instruction, the reason is not nearly as important as the fact they can't and alternative actions are necessary. Why and whether it was a valid reason can be sorted out later. The receiver of the Operating Instruction may not have time in Real-time to figure out which one of the reasons in the requirement is the correct and valid reason. No change made. The SDT disagrees with the addition of the 30-minute time constraint as described above and believes that it may actually be detrimental to reliability. No change made. (6) The SDT has modified Requirement R9 to remove negatively. The SDT disagrees with removing "interconnected" as it believes that this requirement only need apply to immediate neighbors. No change made.		
Georgia Transmission Corporation	No	(1) Purpose: Since Operating Instructions are specific to the operation of the interconnected Bulk Electric System, GTC believes the purpose statement should be revised to be consistent with the terms being utilized and to be consistent with other

Organization	Yes or No	Question 7 Comment
		Standards closely associated such as COM-002-4. Specifically GTC recommends replacing the terms "reliability of the Interconnection" with the terms "reliability of the Bulk Electric System (BES)". (2) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which does not affect the reliability of the BES such as maintenance items, etc. The DP and LSE implement operating instructions on non-BES equipment on a routine basis, but the implementation of operating instructions on BES equipment, or non-BES equipment "affecting the reliability of the BES" is not very routine. GTC believes the intent of this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency "affecting the reliability of the BES". The use of the NERC term "Emergency" would capture this intent. GTC proposes the language "[during an Emergency]" be added after "....shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] ".
Response: (1) The SDT agrees and has modified the purpose statement. See summary consideration for revision. (2) The SDT disagrees that Requirements R3 and R5 should only apply in Emergencies as failure to properly implement an Operating Instruction could be the initiating action the leads to an Emergency. This was the case in the September 2011 Southwest Outage. However, in response to other comments, the SDT has modified Requirements R1 and R2 to reflect that these are Operating Instructions issued to preserve reliability on the BES. See summary consideration for revision.		
NV Energy and MidAmerican Energy	No	R1 and R2: The requirement to act or direct others by issuing Operating Instructions calls into question the ability of a TOP or BA to demonstrate in all cases that Operating Instructions were issued. Would this require the logging and retention of records for each and every Operating Instruction given by a TOP or BA? If so, the volume could easily exceed hundreds of documented Operating Instruction exchanges per day. Also, we recommend changing the phrase "to address its

Organization	Yes or No	Question 7 Comment
		reliability functions" to "to maintain system reliability", as this is more precise and descriptive of the rationale for action. R3 and R5: We note that pending the final definition of Operating Instruction, there may be a significant number of Operating Instructions for which an entity will be required to maintain documentation. R7: The term "assist" is used in describing the required action in response to a requestor. This term is sufficiently vague and ambiguous; therefore, we suggest the use of examples or parameters be provided around the term "assist" in order to clarify the intent and scope of the assistance. Perhaps add clarifiers like "such as delivery of energy, adjustment of reactive power supply or absorption, use of controllable devices, etc." R10: This requires the monitoring of facilities within its TOP area and neighboring TOP areas, including sub-100 kV facilities needed to maintain reliability and the SPS within its TOP area. This reaches prescriptively into the realm of the neighboring TOP's without specifying the degree of monitoring required or whether this is limited to immediately adjacent TOP's or all TOP's "in the neighborhood". I would suggest limitations be placed on the scope of this requirement, as it significantly expands the monitoring task and the demonstration of compliance, and worse, it runs the risk of causing the TOP to lose focus on his own operating area. While there is some merit in operator view into adjacent systems, the wide area view suggested by this requirement is more applicable to the functions of an RC. R9: Recommend that R9 read as: "Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and (removed negatively) potentially impacted interconnected NERC registered entities of forced outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between such entities." R13: The requirement to perform a Real-Time Assessment once every 30 minutes is onerous and goes beyond the directive findings of the SW outage event.

Organization	Yes or No	Question 7 Comment
		Recommend the use of a performance-based requirement rather than a rigid requirement to conduct at least 48 assessments each day. The goal ought to be that the Operator is continuously aware of the impact of any contingency upon the system, not that the assessment is performed on a 30 minute basis. What allowance is provided for loss of contingency analysis tools? Such loss is a reportable event, yet under this requirement it also becomes a violation if not restored and satisfactorily executed within 30 minutes. R14: This requirement compels the TOP to initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-Time Assessment or real time monitoring. The requirement is unacceptably open-ended and does not specify the time frame for such initiation, or even what it means to "initiate" its plan. We suggest specificity be added by the SDT in the text of this requirement. R15: The requirement to "inform" the RC of actions to return the system to within limits also lacks specificity as to the time frame to inform, and the allowable means to inform. As well, it is left to interpretation whether the "actions to return the system to within limits" are those that have been taken or those that will, or could be, taken. We suggest clarification of intent on this requirement and the allowance that electronic SCADA information will satisfy the duty to inform. R16 and R17: The authority to approve does not literally mean that the BA/TOP Operator "must" approve; therefore, there may be an unintended consequence that such maintenance work could be performed without BA or TOP approval. If the intent of the SDT is not met here, clarification is necessary to ensure that all such work must first be approved by the BA/TOP Operator.

Response: The SDT does not believe it will be necessary to retain all data associated with all issuances of Operating Instructions and the compliance could be demonstrated with internal controls such as a procedure and supporting evidence (i.e., recent examples of Operating Instructions) that such a procedure was followed but ultimately this will be up to registered entities to determine how to comply. The SDT has modified Requirements R1 and R2 consistent with your recommendation. See summary consideration for revision.

Organization	Yes or No	Question 7 Comment
The SDT does not believe that the term assist should be defined through enumeration as there could be many ways that a Transmission Operator could provide assistance. During an Emergency, the SDT does not want to limit the options. No change made. Ultimately, it will be up to the Transmission Operator to determine how much of its neighboring Transmission Operators system it needs to monitor maintain its own Transmission Operator Area reliability. Some clarifying changes have been made to the requirement to assist with this understanding. See summary consideration for revision. The SDT has removed "negatively" from Requirement R9 but it not adding "forced". Ultimately, it is important to report the outage regardless of whether it was planned or unplanned. Other additional clarifying changes have been made in response to other comments. The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The		

Organization	Yes or No	Question 7 Comment
SDT did modify the requirement language to change “shall perform a Real-Time Assessment” to “shall ensure a Real-time Assessment is performed” to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The SDT does not believe additional specificity is needed for Requirement R14 and believes putting a timeframe on the requirement may be contrary to reliability. Not all SOLs will require the same time response. No change made. The purpose of Requirement R15 is to notify the Reliability Coordinator that the SOL has been or is being addressed so that the Reliability Coordinator is not also simultaneously issuing conflicting actions. Notification of the Reliability Coordinator before taking actions or after taking actions may be dependent on the unique situation. Thus, the SDT does believe the requirement is as clear as it can be. No change made. The SDT does not agree that authority to approve comes with the option of whether to exercise that authority and believes failure to exercise the authority would be a violation of Requirements R16 and R17. No change made.		
FirstEnergy	Yes	While FirstEnergy generally supports TOP-001-3, we have concern with 30 minutes time frame for updates on Real Time Assessments. This obligation contradicts the 2 hour time frame set in EOP-008. Also, if there is a loss of data communications and there is a need to man substations; it may take longer than 30 min to stage personnel in the field.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity’s Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.		

Organization	Yes or No	Question 7 Comment
· **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Peak Reliability	Yes	o R1, R2: There is a potential conflict arising between a BA and TOP (when the two are not the same company) where a TOP may issue an Operating Instruction to a BA to shed load or bring up generation and at the same time a BA may issue a directive to the TOP to trip/restore a line for potentially the same reliability issue. Will both be required to follow each other's directives? o R10: The way it is phrased gives risk for misunderstanding. Is the Requirement that TOP must "monitor" the status of RAS? Or is the Requirement that the TOP must understand/model the impact of the RAS so that TOPs know the status of any SOL or IROL and whether or not it is being exceeded given the expected RAS action? The way it reads it seems the TOP is only required to "monitor" the RAS, which to Peak means have awareness of the arming status and know when the RAS operates. Also, this Requirement is unclear whether the TOP needs to monitor facilities in adjacent TOPs only to the extent that such facilities actually affect SOLs/IROLs? Adding the phrase "as needed" to "and neighboring Transmission Operator Area" adds more clarity.

Organization	Yes or No	Question 7 Comment
		o R11: "including the status of Special Protection Systems" should be "including the status and impact of Special Protection Systems"
Response: The Balancing Authority and Transmission Operator should be consulting one another when issuing Operating Instructions. However, in the event that there is a conflict in the Operating Instructions, the recipient can use the clause "unless such action… would violate… regulatory…" in Requirements R3 and R5. Both requirements will be regulatory requirements once approved by FERC. Transmission Operators and Balancing Authorities requiring the same entity to take conflicting actions in an Operating Instruction would clearly qualify as a violation of regulatory requirements. No change made. In Requirement R10, the requirement is to monitor the status of the SPS/RAS. The impact of the SPS and RAS will be assessed in the Real-Time Assessment in Requirement R13. The SDT does not believe adding "impact" to Requirement R11 provides any more clarification. Requirement R11 already states the purpose is to ensure that the Balancing Authority is able to perform its reliability functions. It can't do this without understanding the impact of the SPS/RAS. No change made.		
Volkmann Consulting	Yes	See comments on the SOL Exceedance document
Response: See response to SOL Exceedance Document comments.		
Xcel Energy	Yes	Xcel Energy agrees with the proposed changes overall. However, we would like to note that R3 requires entities to comply with Operating Instructions given by the TOP, while in R5 they are to comply with instructions of the BA Operator. We would like to see clarification added in the event that the operating instructions from the TOP and BA contradict each other. Additionally, R10 and R11 both reference Special Protection Systems. We would like to ensure this reference syncs up with the efforts of Project 2010-05.2 regarding the SPS/RAS Definition.
Response: The Balancing Authority and Transmission Operator should be consulting one another when issuing Operating Instructions. However, in the event that there is a conflict in the Operating Instructions, the recipient can use the clause "unless such action… would violate… regulatory" in R3 and R5. Both requirements will be regulatory requirements once approved by FERC.		

Organization	Yes or No	Question 7 Comment
Transmission Operators and Balancing Authorities requiring the same entity to take conflicting actions in an Operating Instruction would clearly qualify as a violation of regulatory requirements. No change made. The SDT is making every effort to sync up with all approved projects and definitions.		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration:1. Requirement R4 - ReliabilityFirst recommends there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform the Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by its Transmission Operator..." 2. Requirement R6 - ReliabilityFirst recommends adding a timeframe to the requirement limiting the time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a time frame, the reliability of the BES may be compromised if an Entity cannot perform an Operating Instruction in a timely manner. ReliabilityFirst suggests the following language for consideration. "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within 30 minutes of receiving an Operating Instruction] of its inability to perform an Operating Instruction issued by that Balancing Authority."
Response: The SDT does not agree with adding 30-minutes to Requirements R4 and R6. There are times when a 30-minute notification would be sufficient and other times it would not be (i.e., when exceeding a 15-minute limit) and could impact reliability. While adding this term would make it more measurable for compliance, it could be contrary to reliability. Each situation is unique regarding how quickly a receiving entity should notify the issue of its inability to follow a directive but it should be quickly. No change made.		

Organization	Yes or No	Question 7 Comment
PJM Interconnection	Yes	PJM does support the standard. We recommend the drafting team use only the term, ‘Facility Rating’ and not use the term ‘derived limit.’ This will provide for consistency is use of one term.
Response: The SDT has replaced ‘derived limit’ with ‘SOLs’ for clarity. See summary consideration for revision.		
PNMR	Yes	
Manitoba Hydro	Yes	
EDP Renewables North America LLC	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

8. **Do you agree with the changes made to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has responded to numerous requests for clarification and has made the following changes based on industry comments:

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

R3. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

R5. Each Balancing Authority shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s).

Data retention: Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90 calendar days period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure.		

Organization	Yes or No	Question 8 Comment
Associated Electric Cooperative, Inc. - JRO00088	No	FOR: TOP-002-4, draft 1 clean, general COMMENT: AECI supports comments posted by the SERC OC Work Group FOR: TOP-001-3 draft 1 clean, definition of Operational Planning Analysis COMMENT: AECI strongly favors the parenthetical sentence that appears as the last sentence within this definition, and believe it can help smaller Responsible Entities to avoid unnecessary cost of compliance where Operational Planning Analysis are required. COMMENT: We recommend the Operational Planning Analysis definitions include the following change: ‘The assessment may reflect inputs including, but not limited to: load, generation output levels,...’ RATIONALE: Inputs in the currently proposed definition are not applicable to all situations where assessments and analysis are needed. Usage of “may” provides recommendation for inputs that are valuable in some situations (and are currently used when applicable), however it does not require these inputs for every assessment, which creates an unneeded burden. FOR: TOP-002-4, draft 1 clean, Requirement R2 and Measurement M2REPLACE: (R2) “an Operating Plan(s)” and (M2) “an Operating Plan” WITH: “one or more Operating Plan(s)”RATIONALE: Grammar FOR: TOP-002-4, draft 1 clean, Requirements and Measurements, R4, M4, R5, M5, R7 and M7COMMENT: These Requirements for BAs really should reside within the BAL Standards.

Response: See responses to SERC comments.

The SDT agrees and has made the suggested change. See summary consideration for revision.

The SDT does not believe this suggestion is necessary as it is implicit that more than one Operating Plan can exist. No change made.

The SDT ultimately agrees that these requirements belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.

Organization	Yes or No	Question 8 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	Definition for Operational Planning Analysis: Delete the parenthetical. This does not clarify what the analysis is. At a minimum replace the word "contracted" with "arranged". R2 - What are the circumstances for using an Operating Procedure vs an Operating Process? R4.4 - Clarify the use of "Capacity and energy reserve requirements, including deliverability capability ". Are these reliability based terms or commercial? R5 - Please clarify the use of the term "impacted". Does this refer to normal operations or is it intended to capture exceptions to the normal operations? R6 - The amount of documentation would be very burdensome. R7 - The amount of documentation would be very burdensome.
Response: The SDT agrees and has revised the definition based on your comment and those of others to address this concern. See summary consideration for revision. R2-The Operating Procedure and Operating Process are both NERC defined terms. The Operating Process is a document that identifies general steps for achieving a generic operating goal, while an Operating Procedure is a document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). R4.4: The terms are reliability-based and consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7. No change made. R5: The SDT believes that under all circumstances, if your plan requires actions on the part of another entity, or that its plan would cause a change that would affect the other entity then you need to communicate their responsibilities. No change made. R6 & R7: The SDT does not believe that this information sharing is overly burdensome and is necessary for the Reliability Coordinator to develop a coordinated plan. No change made.		
MRO NERC Standards Review Forum	No	R5 requires Operating Plans for each component of R4. Note that Operating Plans is defined as a DOCUMENT that identifies a group of activities...

Organization	Yes or No	Question 8 Comment
		Plus the notification of NERC Registered Entities identified in those plans. The NSRF does not know how, for instance, how having a requirement to inform someone of an Interchange schedule, that they established with you, how this promotes system reliability. Having a day ahead Operating Plan should assist the BA in tomorrow's operations. But notifying impacted NERC registered entities is not conducive. PJM, SPP, MISO, etc. are registered BAs and they would be required to have a (DOCUMENTED) Operating Plan every day that will restate generation resource commitments demand patterns and reserve requirements. R5 should be deleted since the IERP only recommends this and it is not a FERC directive.
Response: The SDT believes that Requirement R5 as written does not require a separate Operating Plan for each component of Requirement R4. The SDT does not believe that Requirement R5 requires notification to all entities that provide the Balancing Authority with information but rather takes the inputs from those entities and develops a plan to fulfill the Balancing Authority obligations as defined in the Functional Model. No change made. The SDT believes this requirement is consistent with approved TOP-002-2 Requirement R7 and is supported by the Southwest Outage Report Recommendations along with the recommendation from the IERP. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R4 - Southern suggests that sub requirements, 4.1, 4.2, 4.3 and 4.4 are vague in nature and should be more descriptive by defining specific expectations of what should be addressed. Example: R4.2 as written is unclear as to whether the BAs Operating Plan is expected to address making, accommodating, curtailing, ramping of interchange schedules, etc. R4 and R5 and R7 - It is unclear on what actions would be included in the BA Operating Plan. In the case of the TOP, it is very clear in that the Operating Plan is to address potential SOLs. The R4 subparts include data provided to the BA for reserves planning purposes from other entities. The BA should not be required to notify all

Organization	Yes or No	Question 8 Comment
Georgia System Operations Georgia Transmission Corporation		entities and provide them with the very information those entities provided to the BA as seems to be required in R5. R6 and R7 - Southern suggest that a periodicity for providing data and a deadline by which the respondent is to provide the indicated data should be applied to these requirements to be consistent with corresponding RC requirements, R1.3 and R1.4 in proposed IRO-010-2 Reliability Coordinator Data Specification and Collection.
Response: The SDT believes the proposed language is clear, is consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7. No change made. R4, R5, and R7: The SDT does not believe that Requirement R5 requires notification to all entities that provide the Balancing Authority with information but rather takes the inputs from those entities and develops a plan to fulfill the Balancing Authority obligations as defined in the Functional Model. No change made. R6 and R7: The SDT believes that the documented specification for the data identified in proposed IRO-010-2 will clarify periodicity and deadline issues and therefore that they don't need to be repeated here. No change made.		
Dominion	No	While Dominion agrees conceptually with Requirements 4 and 5 we do not believe they belong in the TOP family of standards.
Response: The SDT ultimately agrees that these requirements belong in the BAL standards but there is no current active project with a scope to address these requirement in the BAL standards. This comment will be added to the NERC issues database to be addressed in the BAL standards at a later date. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, FMPA believes R1 should refer to the performance requirements of FAC-011 R2 or specify "in accordance with its SOL Methodology" so that the breadth of contingencies to be studied is known.
Response: See response to FRCC.		

Organization	Yes or No	Question 8 Comment
The SDT believes the requirement as written is clear. Further the SDT believes that not exceeding any of "Its" limits would require that the entity would have its ratings set by their SOL methodology in conformance with current NERC standards. No change made.		
Duke Energy	No	R1-R3: No comments R4: Duke Energy suggests using alternative language in sub-part 4.4. Currently 4.4 states: We believe the language used is too broad, and could be open to interpretation. We recommend a re-wording to the following:"4.4: Contingency Reserve requirement obligations" This re-wording should reduce any unintended incorrect interpretations. Also, the removal of "deliverability capability" is necessary, as we feel that having the capability to deliver reserve requirements is inherent to the very nature of having Contingency Reserve obligations. R5: Duke Energy suggest using another term other than NERC registered entities. We suggest identifying those entities, per the Functional Model, that specifically interface with the TOP or use the term "Applicable entity". R6: Duke Energy believes that the amount of documentation needed to be retained for this requirement would become very burdensome to the TOP and RC. In addition, the proposed IRO-008-2 requires the RC to coordinate Operating Plans amongst its TOP and BA and this appears to be redundant. Additional concerns we have with this requirement is that there does not appear to be a stipulation for submitting an updated plan, if conditions were to change. For example, an Interchange Schedule is subject to change multiple times. Ultimately, we feel that the RC should have a next day Operating Plan in place to acquire the data necessary for the RC to perform their Operational Planning Analysis, the TOP/BA should then be obligated to follow that plan. We don't agree that a daily document is warranted. R7: See R6 comment. In addition, we believe this requirement belongs in the BAL family of standards.

Organization	Yes or No	Question 8 Comment
Response: R4.4**:** The SDT believes that Requirement R4, Part 4.4 conforms with approved TOP-002-2.1b Requirement R7 which states: Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency. Therefore this is not new terminology and the industry has been correctly interpreting the language. No change made. R5: The SDT agrees and has made the suggested changes**.** See summary consideration for revision. R6 and R7: Proposed TOP-002-4 Requirement R6 requires the Transmission Operator to share its Operating Plan with the Reliability Coordinator whereas proposed IRO-008-2 Requirement R2 requires the Reliability Coordinator to review the plans. Therefore Requirement R6 is not redundant. The SDT further believes that the information shared in Requirement R6 is necessary for the Reliability Coordinator to develop its coordinated plan. No change made.		
Bureau of Reclamation	No	Reclamation suggests that R3 should list the applicable "impacted NERC registered entities" that must be notified when they have roles described in Operating Plans (e.g., Generator Operators, Distribution Providers, etc.).
Response: The SDT believes that the Operating Plan referenced in Requirement R2 identifies which entities need to be notified. No change made.		
SPP Standards Review Group	No	Please see our comment on the definitions of Real-time Assessment and Operational Planning Assessment in Question 7. We suggest modifying Measure M4 to read: 'Each Balancing Authority shall have evidence that it has developed a plan that incorporated the criteria identified in Requirement R4. Such evidence could include but is not limited to dated operator logs or e-mail records.'
Response: Please see response to Q7. The SDT does not believe that the suggested change adds any additional clarity. No change made.		
ACES Standards Collaborators	No	(1) Requirements R2, R3, R6 could be combined with R1. There is overlap within these requirements and the notification requirements are vague.

Organization	Yes or No	Question 8 Comment
		(2) Requirements R4, R7 and R5 could also be combined. There is overlap within these requirements and the notification requirements are vague.
Response: (1) In general, Requirement R2 requires an Operating Plan, Requirement R3 requires notifying affected neighbors, and Requirement R6 requires sharing the Operating Plan with the Reliability Coordinator. The SDT believes that each of these requirements are substantive and necessary as separate requirements. No change made. (2) In general, Requirement R4 requires an Operating Plan, Requirement R5 requires notifying affected neighbors, and Requirement R7 requires sharing the Operating Plan with the Reliability Coordinator. The SDT believes that each of these requirements are substantive and necessary as separate requirements. No change made.		
ISO/RTO Standards Review Committee (SRC)	No	Requirements 6 and 7 are not results-based. We encourage NERC SDTs to focus on developing results-based standards.
Response: The SDT believes that Requirements R6 and R7 are measurable and necessary for system reliability and are results-based. No change made.		
Bonneville Power Administration	No	Concerning R1, BPA suggests clarifying the conditions under which an entity is required to assess whether planned operations will exceed any of its SOLs. Without this clarification, it is unclear whether R1 requires assessing normal system conditions: N-1 or N-1-1. Regarding R4, BPA feels that, because of the time and effort needed for forecasting and analyzing all items included in its sub-requirements, the inclusion of R4.1 and R4.2, which are market-driven, leave insufficient time to complete an adequate assessment for the next day. BPA believes the Standard would be better supported should the word “addresses” be replaced with “considers.” BPA also suggests that the “evidence” mentioned in M4 is ambiguous and suggests rewording M4 to state, “Each Balancing Authority shall have evidence that it has developed a plan to operate to the safe and reliable operation of the BES.”

Organization	Yes or No	Question 8 Comment
Response: R1: The SDT has developed a whitepaper regarding SOL identification that addresses your concern. No change made. R4: The SDT believes the proposed language is clear, is consistent with the terms used in approved TOP-002-2.1b Requirements R5 and R7, and is not solely market-oriented. No change made. The SDT does not believe that the suggested change adds any clarity and actually may cause confusion. No change made.		
CenterPoint Energy Houston Electric LLC.	No	CenterPoint Energy believes that some of the items in the proposed definition of Operational Planning Analysis are redundant. CenterPoint Energy recommends removing “known Protection System and Special Protection System status or degradation” as well as “equipment limitations” as these would be encompassed in Transmission outages, generator outages, and Facility Ratings and do not need to be identified separately. CenterPoint Energy also feels “identified phase angle limitations” are not applicable in all Regions and should be addressed under Section D, Regional Variances.
Response: The SDT believes the current verbiage is necessary and clarifies the requirements. No change made. The SDT agrees with the applicability of the phase angle limitations and included the term “identified” in the definition. If none are identified then none need to be addressed. No change made.		
City of Garland	No	Requirement 1Concern There is no provision for small Transmission Operators who’s Area (number / size of Facilities) is too small to financially justify installing this capability - all TOPs are not created equal.
Response: The SDT believes that an Operational Planning Analysis is required for developing an effective Operating Plan. The proposed definition actually accommodates smaller entities by allowing for 3rd-party handling of the task. No change made.		
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. To be consistent in regards to terminology used in the Standards, ATC suggests that “Operational Planning Analysis” be renamed “Operational Planning Assessment”

Organization	Yes or No	Question 8 Comment
		similar to the term “Real-time Assessment.” For consistency, ATC suggests that this change be made throughout the proposed draft of Standard TOP-002-4. b. Operational Planning Analysis definition - ATC suggests the following changes to the definition for added clarity. Modify the first sentence of the definition by adding the word “single” to read, “An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-single Contingency) for next-day operations.” Otherwise, ATC suggests adding a sentence to the proposed definition to read, “Contingency conditions are limited to the most severe single contingency and the multiple outages specified by its Reliability Coordinator.” c. ATC requests the SDT to clarify the inconsistency between the use of “Operating Plan” in requirements R2 and R3 of TOP-002-4 with the explanation of this term in the “Rationale for Requirement R14” box within the draft TOP-001-3 standard. Specifically, the “Rationale for Requirement R14” explanation states that the “Operating Plan” is a single, general plan and philosophy for dealing with SOL exceedances. However, R2 and R3 of TOP-002-4 refer to the “Operating Plan” as a specific SOL exceedance plan with clearly identified actions by specific NERC registered entities. It is unclear if the TOP is to understand that the Operating Plan is a general philosophy or specific individual plans for each SOL exceedance identified during the next-day assessment. The companion white paper will not be part of the standard so clarity within the standards is important.
Response: The SDT does not believe that the suggested change provides additional clarity. The terminology has been in place for some time now and the industry is familiar with it and it might actually cause confusion to change it at this time. No change made. The SDT does not believe that the change is technically correct as single implies one item and there are instances where entities handle certain select multiple Contingencies as single Contingencies in analysis. No change made. The SDT believes that there is consistency in the use of the current defined term Operating Plan and the explanation in the Rationale Box. While an Operating Plan may contain Operating Procedures and Operating Processes, it may also simply identify a group of activities that may be used to achieve some goal. The companion whitepaper will be appended to the standard. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td>American Electric Power</td><td>No</td><td>R3: If a NERC registered entity is included in an Operating Plan, there is no need to use the word “impacted” as it could add confusion. This word should be removed.</td></tr>
<tr><td colspan="3">Response: Proposed TOP-002-4 Requirement R3 is specific to those entities which play a role in the implementation of an Operating Plan, however it is possible that other entities identified in the plan play a role but are not impacted. No change made.</td></tr>
<tr><td>NIPSCO</td><td>No</td><td>The data retention period required for the analysis is a rolling (6) months, as opposed to the prior data retention period of 90 days (TOP-002 R11). This time frame is too long and needs to be revisited unless there is a valid concern for holding 6 months of analysis.</td></tr>
<tr><td colspan="3">Response: The SDT agrees and has made the suggested change. See summary consideration for revision.</td></tr>
<tr><td>Idaho Power</td><td>No</td><td>I do not agree with this standard as written. The definition of Operational Planning Analysis would seem to require a TOP to have or contract Real-Time Contingency Analysis (RTCA) and all the required inputs.

The definition does not specify what area should be modeled. It would seem that an entity could only model their internal system with their local inputs and be in compliance with this standard. If you are going to mandate RTCA there should be some expectation that external systems be modeled to some extent to better reflect actual conditions. As shown in the Southwest outage only looking at the extents of your system is not adequate.</td></tr>
<tr><td colspan="3">Response: The proposed Operational Planning Analysis definition requires an evaluation of projected system conditions and does not necessitate the use of an RTCA or any other specific tool. No change made.

Requirement R1 defines the area of responsibility as the Transmission Operator Area. The SDT believes in order to study your area for SOLs you have to expand your model to beyond the Transmission Operator Area borders. Proposed TOP-003-3 requires Transmission Operators to look outside its borders into external systems. No change made.</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
David Kiguel	No	R3 and R5: Notification requirement should be extended to all impacted entities, regardless of NERC registration. In some jurisdictions, e.g. Province of Ontario, NERC registration is not required for entities other than the IESO. Same may be possibly valid for other Canadian Provinces.
Response: The SDT agrees with the recommendation and has made the suggested change. See summary consideration for revision.		
ITC	No	In regards to the definition of "Operational Planning Analysis", ITC has concerns that the definition is too prescriptive in specifying required inputs for Next Day Analysis. Specifically, protection system and associated element outages are studied sometime several days ahead using relay clearing time and stability studies. These studies cannot be conducted daily for next day operations as the studies are time intensive and may require dynamic simulation. ITC is fully supportive of studying protection system outages and ensuring that these outages do not reduce the reliability of BES. However the definition should not restrict next day analysis to analyze these outages. Next day analysis is a steady state analysis conducted to ensure that system can operate reliably under all known contingencies. Including protection system outages in next day analysis will require dynamic simulation which is very different than steady state analysis, is very time consuming and does not provide additional value if such analysis has already been conducted when the protection system outage was planned. An alternate and more practical method is to include any potential over trip scenarios due to protections system degradations as these can be simulated by steady state analysis for next day conditions. The definition should be modified to allow the evaluation of protection system status or degradation analysis in the horizon deemed appropriate by the TOP.
Response: The SDT agrees that the Operational Planning Analysis includes a steady state analysis conducted to ensure that the system can operate reliably under all known Contingencies. The Operational Planning Analysis does not require a dynamic simulation each day, but rather that the results of those studies along with any status or degradation of those systems need to be considered in the Operating Planning Analysis. No change made.		

Organization	Yes or No	Question 8 Comment
Lincoln Electric System	No	As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the plan is modified or not. To avoid unnecessary administrative work, recommend each Operating Plan only be provided once to the RC, unless notified by the RC.
Response: The SDT believes that this needs to be a 'push' mechanism rather than a 'pull' based on the Reliability Coordinator specifically requesting the Operating Plan in order to make this a 'routine' event that can be handed without becoming a burden. The SDT also believes that Reliability Coordinators will work with its Transmission Operators to come up with an arrangement so that duplicative Operating Plans do not need to be submitted. No change made.		
Electric Reliability Council of Texas, Inc.	No	The current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4. For R4, the SDT should consider consistency of use of "Demand patterns" and "Load Forecast".
Response: See response to comments for IRO-008. See response to comments for IRO-008. The SDT believes that the terms have been used correctly. No change made.		
Texas Reliability Entity	No	1) R2: R2 should be explicit on the time frames that an SOL exceedance must be mitigated within TOP Operating Plans. Recommend adding language from or referencing the SOL Performance Summary, Figure 1 from the Project 2014-03 SOL Exceedance White Paper. The concept contained in the SOL whitepaper is clear but it must be transferred to the Operating Plan development process to ensure that SOLs are mitigated in the appropriate time frame to avoid any thermal or stability limit violations.

Organization	Yes or No	Question 8 Comment
		2) R4: Recommend adding a new BA requirement to have an Operational Planning Analysis (in line with R1 language for the TOP). Currently it appears there is a gap for the BA responsibilities. The BA should also have a requirement for an Operational Planning Analysis in order to develop their Operating Plan for the next day. The NERC Functional Model lists BA responsibilities "ahead of time" for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as "The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ...." 3) R's 3, 5, 6 and 7: Requirements R3, R5, R6 and R7: Recommend adding language similar to this: "Such notification (Plan) shall be delivered before the start of the day to which it applies." Requirements R3, R5, R6 and R7 require the TOP (R3 and R6) and the BA (R5 and R7) to notify either impacted NERC registered entities or the RC but no time frame for when the notification must occur. The reliability benefit of these deliveries is much reduced if they are made too late for appropriate actions to be taken by the receiving entities.
Response: 1) The SDT believes that any needed timeframe will be part of an entity's Operating Plan. In addition, the whitepaper will be appended to the standards. No change made. 2) The SDT does not believe that the Balancing Authority needs to perform an Operational Planning Analysis and that creation of an Operating Plan fulfills the needs for reliability. No change made. 3) The SDT believes that timeframes for delivering this information will be set up on case-by-case basis, that most areas already have such stipulations in place, and that they are all different based on a particular area's needs. Any attempt to mandate a national limitation would be an exercise in futility. The SDT believes that the suggested language is not necessary. No change made.		
NV Energy	No	R1: Requires that the TOP shall have an OPA that will allow it to assess whether planned operations for the next day within TOP area will exceed any SOLs. This requirement fails to acknowledge that the "next day" for some OPAs will be several

Organization	Yes or No	Question 8 Comment
MidAmerican Energy		days in the future and not the immediately following day. Without that provision, it would mean that next day analyses must be conducted 365 days per year (if it only is valid for the "next" day). We suggest that the language be rephrased as follows: "...that will allow it to assess whether its planned operations for the Operations Planning horizon within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." R2: Same issue as with R1. Suggest changing the time frame of the Plan to be the Operations Planning horizon. R3: As stated, each TOP shall notify impacted NERC registered entities identified in the Operating Plan cited in R2 as to their role in the Plan. Suggest clarifying language inserted as follows "to the extent that any NERC registered entities are impacted" to allow for the likelihood that none are impacted. The requirement of notifying "four or more impacted NERC registered entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s)" is vague and potentially unenforceable. Suggest the SDT drop the four or more than 15% for "notify adjacent negatively impacted NERC registered entities". Is posting of the guide on the Region's web-site sufficient? If not, how do we define 15% of the impacted entities? R4: Here the BA shall have an Operating Plan. This has the same time frame issue as with R1 and R2, and we propose similar resolution.

Response: The SDT believes that the important aspect for reliability is to have a study that applies to the next day. If nothing changes from day to day then a new analysis would not be required. No change made.

Requirements R1, R2, and R4 are already identified as "*Time Horizon: Operations Planning*". No change made.

R3: The SDT believes that the term "impacted" excludes those entities not identified as such in the plan and that the suggested language does not add any clarity. No change made.

Organization	Yes or No	Question 8 Comment
The SDT believes that the VSL language is clear. An entity knows how many other entities are impacted from its study and should be easily able to determine the 15% limit. No change made.		
SERC OC Review Group	Yes	In R3, M3, R5, & M5 a suggestion to change wording from “notify” to “coordinate”. Suggested wording in R3, R5: “shall coordinate with NERC registered entities identified in the Operating Plan(s)” instead of “shall notify impacted NERC registered entities”. Suggested wording in M3, M5: “shall have evidence that it coordinated impacted”.
Response: The SDT does not agree with replacing “notify” with “coordinate” because coordination is not measurable where notification is. Furthermore, the SDT believes that the notification initiates coordination. No change made.		
Peak Reliability	Yes	o R4.3. Does “demand pattern” simply mean a load forecast? If not, it should be clarified. If so, it should say “load forecast” as this term is more widely understood and used in the industry.
Response: The SDT believes that Load forecast can be interchanged with demand pattern. No change made.		
Tri-State Generation and Transmission Association, Inc.	Yes	As it is written R1 does not require the TOP to perform the analysis. The team should modify the requirement to "Each TOP shall perform an Operational Planning Analysis...."
Response: The SDT requires the Transmission Operator to have an Operational Planning Analysis allowing for flexibility in obtaining the Operational Planning Analysis. No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	

Organization	Yes or No	Question 8 Comment
PPL NERC Registered Affiliates	Yes	
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
ReliabilityFirst	Yes	
PNMR	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Ameren	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 8 Comment
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Hydro One	Yes	
INDN - Independence Power & Light	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

9. Do you agree with the changes made to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT changed the Implementation Plan for Requirements R1 through R4 from 10 months to 9 months. Most of the other comments received were about clarifications of the proposed language. The SDT has provided the requested clarification and in addition has made the following change based on industry comments:

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	To be consistent with other approved standards, add an "s" to "compliance audit", self-certification", "complaint" and change "compliance investigations" to "compliance violation investigation" in Section C. Compliance, sub-Part 1.2 Compliance Monitoring and Enforcement Processes. To be consistent with other approved standards, remove the bullets from Section C. Compliance, sub-Part 1.3 Data Retention. Under the section "Definitions of Terms used in the Standard" it is stated that there are no new or revised definitions proposed in this standard revision, however, the standard's use of "Operational Planning Analysis" is a revision to its definition.
Response: Since the Compliance Processes language is meant to reference those processes that are approved as part of the ERO's Uniform Compliance Monitoring and Enforcement Processes (CMEP), NERC is replacing the list of processes with a reference to that section of the NERC Rules of Procedure. A reference to the updated definition of "Operational Planning Analysis" has been added to proposed TOP-003-3 as suggested. Based on this comment, the definition of "Real-time Assessment" has also been added. And conforming changes were made to proposed IRO-010-2.		

Organization	Yes or No	Question 9 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc.	No	R1 - Time Horizon should include Real-Time Operations and Same-Day Operations. R1.1 and R1.2: Does this mean a generic type of data required or a detailed list of data points? R2 - Time Horizon should include Real-Time Operations and Same-Day Operations. R2.1 and R2.2: Does this mean a generic type of data required or a detailed list of data points?
Response: The data specification is set up in advance in order for the Transmission Operator/Balancing Authority to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made. The requirements are designed to be a detailed list of data points.		
MRO NERC Standards Review Forum	No	R3 and R4 need to be reworded as it is believed that it is a request for data from the TOP (R3) and BA (R4) to other entities to be included into the prescribe analysis or assessment. Recommend R3 (and similar for R4) to read as: "Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment".
Response: The SDT believes that the requirements are clear as written. No change made. The SDT does not believe that this suggested change adds clarity. No change made.		
Dominion	No	Dominion does not agree with R1.1 as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process.

Organization	Yes or No	Question 9 Comment
		Dominion does not see a distinct difference between sub-requirements 1.3 and 1.4. We believe that periodicity infers the deadline. Dominion does not see a distinct difference between sub-requirements 2.3 and 2.4. We believe that periodicity infers the deadline.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. Requirement R1, Part 1.3 (and Requirement R2, Part 2.3) refers to the periodicity of the data, i.e., how often the data must be supplied. Requirement R1, Part 1.4 (and Requirement R2, Part 2.4) refers to the deadline for the initial provision of the data point, i.e., when you need to respond to a new request for data. No change made.		
Florida Municipal Power Agency	No	FMPA supports the comments of FRCC Operating Committee (Member Services). In addition, R1 and R2 should specify a “minimum” set of data requirements. This is especially apparent when protection system status is called out in 1.2 and 2.2, but the status of the Facilities being protected is not called out - which is more important to reliability? Due to the ambiguity of what is and is not included in R1 and R2, other SDTs for other standards were unwilling to accept that there is duplication (e.g., VAR-002, which was just revised, requires notification of voltage regulator status, and information about GSUs and tap settings, items which should also be included in the data specification). The only way to eliminate the duplication, redundancy and confusion in the standards will be to develop a minimum list of data in R1 and R2 so that it is clear that the data is included. FMPA believes that lack of specificity, while presumably simplifying the standards, actually makes them more complicated because we are unable to resolve overlap between standards. As such, we propose the SDT develop a “minimum” set of data, notification, information, etc.,

Organization	Yes or No	Question 9 Comment
		requirements as an attachment to the standard. TOPs and BAs can always specify more if so desired. In R5, what data is needed from the IA that is not provided by the BA? Likewise, all of the data needed from an LSE can also be provided by the DP (i.e., load forecasts). As a result, FMPA recommends eliminating IA and LSE from the requirement.
Response: The SDT believes that the requesting entity, in this case the Transmission Operator/Balancing Authority, is in the best position to know what it needs to preserve reliability. One size does not fit all here as each system is different. The requirement is written to respect that fact and to allow individual Transmission Operators/Balancing Authority's to craft the list as they see fit using its professional judgment. The Transmission Operator and Balancing Authority would always be able to suggest additional data points if the Transmission Operator/Balancing Authority did not request them initially. No change made. The SDT agrees and has removed the Interchange Authority from this requirement. There are active discussions about the future role of the Load-Serving Entity but for the moment it is included in the Functional Model v5. The SDT is required to follow that document in its work. If the group looking into the deletion of Load-Serving Entity decides to eliminate it, it will be the responsibility of that group to come up with a plan to bring the body of standards up to date. See summary consideration for revision.		
Duke Energy	No	R1: Duke Energy believes the Time Horizons should include Same-Day Operations and Real-Time Operations. This would capture the Time Horizon where Real-time monitoring and Real-time Assessments occur. R2: As written, Duke Energy believes the Time Horizon should be modified to Same-Day Operations and Real-Time Operations to be consistent with Real-time Monitoring. R3: No comments R4: No comments R5: No comments

Organization	Yes or No	Question 9 Comment
Response: The data specification is set up in advance in order for the Transmission Operator/Balancing Authority to receive the data it needs when it needs it. Therefore, the Time Horizon is not a Real-time or same-day issue but a 'planning' issue and is accurately recorded as Operations Planning. No change made.		
Bureau of Reclamation	No	Reclamation disagrees with TOP-003-3's proposal to require Generator Owners, Generator Operators, and Transmission Owners to meet any data specification outlined by Transmission Operators or Balancing Authorities. Like TOP-003-1, TOP-003-03 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage. Reclamation does not support TOP-003-3 because it does not clearly define what types of data entities can request or may be required to provide, and is likely to create operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas.
Response: Proposed TOP-003-3 allows the Transmission Operator and Balancing Authority to request the data that is needed to operate reliably. This can differ depending on the topology of the interconnected Transmission system, which could result in different data requirements and for different entities to come into play such as, Generator Owner, Generator Operator, and Transmission Owner. No change made. The Transmission Operator and Balancing Authority can continue to specify specific times for certain data in the data specification concept just as they did before. It can now be done on a case-by-case basis which is better for reliability. No change made. Proposed TOP-003-3 allows the Transmission Operator and Balancing Authority to request the data that is needed to operate reliably. This can differ depending on the topology of the interconnected Transmission system, which could result in different data requirements and for different entities to come into play such as, Generator Owner, Generator Operator, and Transmission Owner. No change made.		
SPP Standards Review Group	No	The Rationale Box under the Applicability Section explains why the Interchange Authority was absolved of responsibility for IRO-010-2. That same justification should

Organization	Yes or No	Question 9 Comment
		be used to remove the Interchange Authority from the Applicability Section of TOP-003-3. There is some confusion as to just what needs to be included in the data specification required in Requirement R1. In order to minimize confusion we recommend that the drafting team include clarification in the Application Guidelines which, for example, states that the specification does not have to be a point-by-point listing of all data points to be exchanged. Capitalize 'Part' in the Rationale Box for R1. Replace the 2nd line in the 2nd paragraph in the Rational Box with 'The language has been moved from approved PRC-001-1.' Capitalize 'Part' in the Rationale Box for R5.
Response: The SDT agrees and has removed Interchange Authority. See summary consideration for revision. Ultimately, a point-by-point listing will be necessary, although the process may begin with a higher-level specification, such as "all line statuses, MW/MVAR flows and bus voltages for all transmission assets controlled by this entity." It is doubtful that a Transmission Operator/Balancing Authority would necessarily know all of the points in detail for a new entity in its area, but likely that it would know the listing of points for existing, mature entities of that type. No change made. The SDT agrees and has made the suggested changes. The SDT agrees and has made the suggested change. The SDT agrees and has made the suggested change.		
ACES Standards Collaborators	No	(1) Requirement R5's language of "mutually agreeable" is challenging for compliance because it requires additional documentation to show that the data was submitted in a "mutually acceptable format." The requirement should be that entities must submit the applicable data by the required timeline. What should be a straight-forward process has been complicated for compliance purposes with this language.

Organization	Yes or No	Question 9 Comment
Response: The SDT does not believe that the suggested change adds clarity. No change made.		
Rayburn Country Electric Cooperative	No	Similar to my comments on IRO-001 and TOP-001 I think this could be combined with IRO-010 in a similar manner. GROUP 1Any of the following: Reliability Coordinator Balancing Authority Transmission Operator GROUP 2Any of the following: Transmission Operator Balancing Authority Generator Owner Generator Operator Interchange Authority Load-Serving Entity Transmission Owner Distribution Provider R1. GROUP 1 shall maintain a documented specification for the data necessary for it to perform its analysis, monitoring and assessments as required. The data specification shall include, but not be limited to: R2. GROUP 1 shall distribute its data specification to entities that have data required by (GROUP 1) to perform its analysis, monitoring and assessments. R3. A GROUP 2 member receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: 3.1. A mutually agreeable format 3.2. A mutually agreeable process for resolving data conflicts 3.3. A mutually agreeable security protocol Any specificity related to data required by each respective function should be identified within their data specification not within the reliability standard. For example, if the RC needs sub 100kV information, that can be identified with justification within the data specification.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Rutherford EMC	No	In the Table of Compliance Elements, the severity and risk for R5 is medium with only a Severe VSL. All other requirements in this standard are low and have graduated levels of severity. In IRO-10, the same failure has graduated levels of severity. This is inconsistent and should be rectified.
Response: Please see response to question 14.		

Organization	Yes or No	Question 9 Comment
Volkmann Consulting	No	TOP-003 should have additional requirements that requires the TOP or BA to determine and communicate any deficiency of data received back to the applicable entity providing the data. TOP-003 requires the sending of data to the TOP or BA, but does not require the determination of adequacy. For larger systems, it is impossible to prove every piece of data is being sent per the specification. In all cases the TOP or BA know if they have enough data, but performance of its real-time processes and tools. The TOP or BA should be required to communicate data deficiencies and not rely on the Audit process.
Response: The SDT believes that the requirements are written such that the onus for performance is on the Transmission Operator/Balancing Authority. Therefore, the Transmission Operator/Balancing Authority will have every reason to be continually checking the data for accuracy or any deficiencies and that this becomes a technicality that does not rise to the level of a mandatory standard. No change made.		
City of Garland	No	Requirement 1Concern There is no provision for small Transmission Operators who's Area (number / size of Facilities) is too small to financially justify installing the capability to run the analysis and assessment - all TOPs are not created equal.
Response: The SDT has allowed for the possibility of an entity performing analysis and assessment on its own or by contracting for it thus allowing for a minimal cost solution. For example, ERCOT could run these studies for Garland under the existing CFR. No change made.		
Ingleside Cogeneration LP	No	R1.1 allows the Transmission Operator to require downstream entities to provide certain sub-100 kV data and external network data needed to support operational reliability. Although ICLP agrees with the fundamental premise, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new Definition of the BES. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. Without this

Organization	Yes or No	Question 9 Comment
		limitation, we can see that the standard will be applied unevenly across Transmission Operators; which works against the fundamental intent of reliability standardization. Secondly, ICLP does not see the reasoning behind moving the responsibility for maintaining a mutually agreeable data format, data conflict resolution process, and security protocol to the data providers (R5). The TOP and BA should provide those specifications and processes under Requirements R1 and R2. If there is an issue with the term “mutually agreeable”, the onus could be put on the data provider to demonstrate that an alternate format/process/protocol is needed in their specific instance.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. “Mutually agreeable” allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can’t force a solution on the other entity when that entity may not be physically capable of performing**.** No change made		
American Transmission Company	No	ATC requests that the SDT consider the following recommended modifications: a. R1, R1.1, and R3 - See comments submitted under TOP-001-3 (Question #7) regarding proposed changes to the definition of “Real-time Assessment”. If ATC’s first proposal for changing the definition of “Real-Time Assessment” is not implemented, to eliminate redundant wording related to Real-time requirements, ATC suggests the term “Real-time monitoring” be removed from Requirements R1, R1.1, and R3 since the “Real-time Assessment” definition shown in draft Standard TOP-001-3 already requires assessing existing operating conditions. b. R1.1 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.1 be modified by replacing “as deemed necessary by

Organization	Yes or No	Question 9 Comment
		the Transmission Operator" with "needed to maintain reliability within its Transmission Operator Area." c. R1.2 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing "that impacts System reliability" with "needed to maintain reliability within its Transmission Operator Area." d. R1.2 - To provide consistency with proposed Requirement R10 of TOP-001-3, ATC suggests that Requirement R1.2 be modified by replacing "that impacts System reliability" with "needed to maintain reliability within its Transmission Operator Area." e. R2 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2 be modified by replacing "perform its analysis functions and Real-time monitoring" with "perform its reliability functions." f. R2.1 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.1 be modified by replacing "perform its analysis functions and Real-time monitoring" with "perform its reliability functions." g. R2.2 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R2.2 be modified by replacing "that impacts System reliability" with "impacts generation or Load." h. R4 - To provide consistency with proposed Requirement R11 of TOP-001-3, ATC suggests that Requirement R4 be modified by replacing "analysis functions and Real-time monitoring" with "reliability functions."

Response: a. The SDT does not believe that the suggested change adds clarity. No change made.

b. The SDT does not believe that the suggested change adds clarity. No change made.

c. The SDT does not believe that the suggested change adds clarity. No change made.

d. The SDT does not believe that the suggested change adds clarity. No change made.

Organization	Yes or No	Question 9 Comment
e. The SDT does not believe that the suggested change adds clarity. No change made. **f.** The SDT does not believe that the suggested change adds clarity. No change made. g. The SDT does not believe that the suggested change adds clarity. No change made. h. The SDT does not believe that the suggested change adds clarity. No change made.		
American Electric Power	No	Please provide reasoning for the removal all references to the NERC Confidentiality Agreement from TOP-005-2. R1: How detailed would the data specifications need to be, especially in regards to data between other entities, in order to satisfy the requirement? R3: For data taken from NERC SDX, how would a data specification be sent? There is an established process in SDX for sharing data, and this proposed standard does not align with it. R5: This does not align with current practices of going through the RC for transferring operational data between NERC entities. R5.3: The phrase "Mutually agreeable security protocol" is vague and is subjective due to its potential interpretation by various entities and regions.
Response: As pointed out in the mapping document, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. As detailed as necessary for the issuing entity to assure reliability. It could initially be a high-level request, with discussion and interaction to produce the list of data points necessary to assure reliability. The mechanism by which the data is shared is part of "how" this is accomplished. The SDT believes that SDX and other technologies do fit within this standard. The entity issuing the data specification may need to review whether the periodicity of SDX data is sufficient to meet its reliability needs. Transferring data through a Transmission Operator/Balancing Authority is part of "how" this could be accomplished. This would adhere to the requirements as long as periodicities, etc. are met.		

Organization	Yes or No	Question 9 Comment
The standard anticipates data to be supplied via a secure mechanism/medium. The exact mechanism/medium is part of the "how" it is to be accomplished. No change made.		
Ameren	No	R1: We ask the drafting team for clarification. What data would be necessary from outside entities for us to perform "Operational Planning Analyses"? Would this need to be forwarded to those entities? R5: We ask the drafting team for clarification; how will we be able to prove compliance with this unless someone provided us with any data specifications satisfying said data specification transfer if it means an automatic type of data dump. Does the drafting team mean providing some data manually on a real time basis (line just tripped, etc.), that would fall in the TOS realm or with ICCP data transfer?
Response: The Transmission Operator runs its own Operational Planning Analysis and, therefore, it is in the best position to know what data is needed, and if the data is controlled/supplied by an external entity, then it must supply the data specification asking for that data to be supplied. Measure M5 states "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities. " The SDT believes that this gives ample opportunities for proving compliance. A simple attestation from the requesting entity that the data has been supplied in accordance with the specification is one possible way to prove compliance.		
Liberty Electric Power, LLC	No	See comment provided for the similar IRO standard.
Response: See comment response for the IRO standard.		
ITC	No	Regarding R1.1, the inclusion of sub-100 kV facilities is not relevant as the requirement should focus monitoring on BES elements only. If a sub-100 kV facility is included in BES per the definition it should be monitored.

Organization	Yes or No	Question 9 Comment
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made.		
Electric Reliability Council of Texas, Inc.	No	Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: Protection Systems were added due to concerns raised in NOPR paragraph 78. The intent of such changes is to ensure that Transmission Operator/Balancing Authority can maintain an appropriate level of situational awareness. While the SDT believes that this will result in an additional burden on entities, it believes that this incremental increase is relatively minor and necessary for reliability. No change made. The SDT believes that the implementation time frame of 12 months is adequate. Nearly all, if not all, of the data that a Transmission Operator/Balancing Authority might need for reliability is already in place and telemetered to the Transmission Operator/Balancing Authority. The 12 month period will allow for any additional work that might be needed to be accomplished. Adoption of this standard does not create a massive new data transfer effort. No change made.		
Texas Reliability Entity	No	1) General: Texas Reliability Entity disagrees with use of the phrase "specification for the data necessary" in the Requirements of this standard. This phrase appears to meet the definition of the so-called "fill-in-the-blank" standards that FERC and the industry are seeking to avoid. NERC's Work Plan for Addressing Fill-In-The-Blank Reliability Standards (October 4, 2006) defines fill-in-the-blank standards as

Organization	Yes or No	Question 9 Comment
		"...those that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the regions." This standard as written does exactly that: depends on regional criteria or procedures not currently in standards that are needed for an entity to achieve compliance. This standard does not meet the following criteria identified in NERC's Quality Objectives: clear and defined performance requirements, measurable, complete and self-contained standards and consideration of comments. The SDT addressed multiple commenters who expressed concern with the phrase "specification for the data necessary" during the comment period for TOP-003-2 under Project 2007-03 with the following: "The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made." The response indicates that the SDT may not have fully considered the concerns that were raised by the lack of specificity within the standard as currently written. While Texas RE understands the SDT is trying to allow flexibility to determine what data they need to perform their duties, there must be a minimum set of data that each TOP and BA needs to adequately fulfill their operational and planning responsibilities, therefore contributing to the reliability of the BPS. Recommend expanding R 1.1 and 2.1 to include a list of "at a minimum, data specification must include..." applicable to what the TOP and BA respectively need to perform their functions. Alternatively, recommend adding technical guidance similar to recently FERC approved MOD-032-1, Attachment 1 and application guidelines to include the types of data that must be provided by each TOP, BA, GO, GOP, IA, LSE, TO and DP as required in R5. 2) R1.1: Recommend enclosing in commas and moving the phrase “needed by the Transmission Operator” to before “sub-100”. The phrase “needed by the Transmission Operator” is positioned wrong to be clearly understood as applying to the “including sub-100 kV data and external network data” portion of the Requirement. It appears in the paragraph as a modifier that applies to the entire list of data and information.

Organization	Yes or No	Question 9 Comment
		3) R 1.2: The meaning of the word "Provisions" is unclear in the context of this sub-requirement. Is it meant that the RC shall provide a tool (such as a web portal) for entities to notify the RC of Protection System and Special Protection System status? Or is it meant that the RC shall identify how notification should be made? If the latter, the word "provisions" should be replaced by "specifications". (Same comment was made for IRO-010, R 1.2) 4) R2: Recommend replacing “analysis functions” with “Operational Planning Analysis”. It appears there is a gap for the BA responsibilities. Under the Functional Model, the BA is responsible ahead of time for integrating resource plans, including compiling load forecasts, approving operational plans and commitments from GOs, receiving generation maintenance schedules, etc. The Functional Model language mirrors the language contained in the definition of Operational Planning Analysis such as “The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; interchange; ....” 5) R3 and R4: Recommend adding the word "current" in front of "data specification" to account for the possibility that the data specification can change. For example if the specification is changed from average MW capability for the year to the summer rating then the revised (or "current") data specification must be distributed to entities that have data required by the TOP (R3) or the BA (R4).

Response: 1) The SDT disagrees. Each Reliability Coordinator/Transmission Operator/Balancing Authority faces unique challenges that should allow them to be able to tailor the data specification accordingly. No change made.

2) The SDT does not believe that the suggested change adds clarity. No change made.

3) “Provisions” allows for multiple solutions – the standard only states what must be done, not how it must be accomplished. No change made.

4) The SDT does not agree that the Balancing Authority should be required to have an Operational Planning Analysis. The Balancing Authority does perform analyses that are both Real-time, day-of, next-day and forward looking, but these are not the same as the Operational Planning Analysis. No change made.

Organization	Yes or No	Question 9 Comment
5) The SDT does not believe that the suggested change adds clarity. No change made.		
Georgia Transmission Corporation	No	(1) GTC disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity if determined to be BES. (2) Several aspects of this requirement meet Paragraph 81 criteria because they are administrative in nature that do not directly impact reliability, are redundant, and handle data requests and submittals.
Response: (1) Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process, it is also true that there may be sub-100 kV points that are not needed as part of the BES but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made. (2) This requirement codifies the requirement to make available the data necessary to assure reliability and to address specific issues raised in the NOPR. The SDT does not agree that these are administrative requirements. No change made.		
Salt River Project	No	R2 requires entities to provide a specification for all data necessary for analysis and real time monitoring which will result in a massive specification that could include all ICCP points used for modeling, dynamic signals & pseudo ties, BA tie lines, elements of NSI & NAI, SPS & RAS status & alarm points and a multitude of other data that may be required. The data required here is very dynamic and will change in a very short period of time. Any specification created initially to meet this requirement will very soon become outdated. R2.3 requires a BA to review the periodicity for providing data. Does a BA need to review each data point and determine appropriate periodicity? Does this periodicity apply for a BA's internal data, external data, or both? With the scan rates already required in BAL-005-1b R8, why is this requirement necessary?

Organization	Yes or No	Question 9 Comment
		R2.4 references a respondent for data but does not specify who the respondent would be. R4 requires BAs to distribute data specifications to other entities. For a BA with many adjacent entities, this will become a significant increase in workload and resources to distribute the specifications, and then document and maintain compliance evidence that this specification was received and that data was provided by each entity. This is burdensome and would only minimally increase reliability. A BA with several adjacent entities will need to negotiate a format, conflict resolution and security protocols with each individual entity per R5.1, R5.2, and R5.3. This will result in a significant number of individual agreements with each entity. Creating these agreements, maintaining these agreements and then maintain compliance evidence for each agreement is burdensome with only a minimal enhancement in reliability. SRP suggests the creation of a regional committee to address those conflicts in exchanging necessary operational data that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this standard.

Response: The SDT believes that the process described is flexible enough to allow for updates as frequently as necessary to support reliability. No change made.

Periodicity is determined by the Balancing Authority to support its reliability needs. The periodicity may be different for different points and the Balancing Authority is in the best position to determine the exact periodicity needed. The indicated requirement only applies to ACE calculation data. The Balancing Authority deals with more than just that data so the periodicity requirement is needed. No change made.

The respondent, from the context of the sub-requirement, is the entity that has received a data specification from the Balancing Authority. No change made.

Balancing Authorities with multiple interconnections must coordinate with all of their neighbors in order to assure reliability. This burden is not changed significantly with this requirement. No change made.

Organization	Yes or No	Question 9 Comment
NV Energy MidAmerican Energy	No	R1 and R2 represent a significant documentation effort on the part of TOPs and BAs. It is supportable as written, but it will require a significant effort within typical grid operations staff to maintain the data specification and process the interactions with the entities who will be supplying the data. R3 and R4 should be clarified as: "Each Transmission Operator shall distribute its data specification to entities that have data (add) submittal requirements by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment". This will limit the specification to only that data which is needed for these analyses, monitoring and assessments. Regulators have stated they will not accept attestations in the future.
Response: Thank you for your support. The SDT does not agree. The Transmission Operator and Balancing Authority have the right to ask for any data that is needed to support reliability. No change made. The SDT is not aware of any movement to not accept attestations in the future. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	Yes	1) In R3 & R4, insert term 'NERC registered' before 'entities'. Due to temperature readings being obtained from the National Weather Service (NWS), some may consider the NWS to be an entity requiring the data specifications. Current: "Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment." Suggested: "Each Transmission Operator shall distribute its data specification to NERC registered entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment." 2) Suggestion to add "R5.4 A mutually agreeable reliability need"

Organization	Yes or No	Question 9 Comment
		3) In R5, for the entity receiving a data request, it would be preferred that some language is added to allow them to coordinate the request to ensure a sufficient reliability need. See response to Question 4 above.
Response: The SDT does not believe that the suggested change adds clarity. No change made. The standard gives the Transmission Operator/Balancing Authority the power to request anything needed for reliability. There is no requirement to demonstrate the need for this data, as, by definition, the Transmission Operator/Balancing Authority is the function charged with preserving the reliability of the interconnected power system for its area. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The word ‘Coordinator’ should be added after the word ‘Reliability’ in the last sentence of the Rationale paragraph for R1. Southern suggest adding the words, ‘NERC registered’ after the word ‘to’ in requirement’s 3 & 4 and Measures 3 & 4, and adding the phrase, ‘a reliability-related need for’, after the words, ‘that have’ in requirement’s 3 & 4 and Measures 3 & 4. Suggested Requirement language: R3. Each Transmission Operator shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator’s Operational Planning Analysis, Real-time monitoring, and Real-time assessment.R4. Each Balancing Authority shall distribute its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority’s analysis functions and Real-time monitoring. Suggested Measure language: M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to NERC registered entities that have a reliability-related need for data required by the Balancing Authority’s analysis functions and

Organization	Yes or No	Question 9 Comment
		Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.
Response: The Rationale Box actually contains the word "Coordinator" but it was obscured in the posted version due to a formatting issue. This has been corrected. The SDT does not believe that the suggested changes add clarity. No change made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	Yes	We agree with all the elements in the standard except the VSL for R5. Please see our comments under Q14, below.
Response: See response to question 15.		
Peak Reliability	Yes	R5: The IA should be removed. In the INT Re-write project, all operational requirements on the IA were removed and put on the sink BA. Consistent with that, the IA should be removed from this Requirement. R5: The "mutually agreeable" language is potentially problematic, as it is unclear how the entity will receive the data if they cannot reach agreement on the format. Using "a clearly defined format" would be better.
Response: The SDT agrees and has removed Interchange Authority from the standard. See summary consideration for revision. "Mutually agreeable" allows for maximum flexibility in this task while recognizing that the process is a two-way street where one entity can't force a solution on the other entity when that entity may not be physically capable of performing. No changes made		
ReliabilityFirst	Yes	ReliabilityFirst submits the following comments for consideration: 1. Requirement R1, Part 1.1 - The phrase "as deemed necessary" is ambiguous and leaves the

Organization	Yes or No	Question 9 Comment
		requirement open to interpretation and therefore, difficult to enforce. To provide specificity, the requirement should state "... including sub-100 kV but greater than 50 kV data". This language is consistent with the NERC BES definition, and has a technical justification developed by that SDT.
Response: Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV necessary for the Transmission Operator to fulfill its responsibilities. While it is true that most of the relevant sub-100 kV data will come from those sub-100 kV elements that have been brought into the BES through the exception process or that are over 50 KV, it is also true that there may be sub-100 kV points that are not needed as part of the BES or over 50 kV but which the Transmission Operator would like to have to flesh out its models. The requirement as written will allow the Transmission Operator to obtain this data. No change made.		
Idaho Power	Yes	I do not have a problem with TOP-003-3 but feel it should be combined with IRO-010-2 as the requirements are basically the same only the applicability is different.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 9 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Xcel Energy	Yes	
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 9 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Response: Thank you for your response.		

10. The mapping document posted on the project page explains how the drafting team believes Requirements from 5 IRO standards that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards IRO-003-2, IRO-004-2, IRO-005-3.1a, IRO-015-1, and IRO-016-1? If not, why not? Please be specific.

Summary Consideration: The overwhelming majority of the commenters agreed with the retirements as proposed and no changes were made to the list of proposed retired standards.

Organization	Yes or No	Question 10 Comment
Duke Energy	No	Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 IRO standards that are proposed for retirement.
Response: Thank you for your response.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with retirement of IRO-003-2, IRO-005, IRO-015, and IRO-016. ERCOT does not agree with the current method to retire IRO-004-2 because the current definition for Operating Instruction is for Real Time only.
Response: The SDT believes that the "Real-time" term in the definition of an Operating Instruction describes the operating personnel issuing the command, but the SDT does not believe that the "Real-time" term applies to the timeframe of the intended "change or preserve" action, nor does it apply to the timeframe of the identified reason for the command. Therefore, personnel responsible for Real-time operations of a Reliability Coordinator could issue a valid Operating Instruction to a Transmission Operator, Balancing Authority, or Transmission Service Provider to take or plan to take appropriate actions to address projected system conditions that were identified in an Operational Planning Analysis of the next day. No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 10 Comment
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
FRCC Operating Committee (Member Services)	Yes	
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SERC OC Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 10 Comment
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
SPP Standards Review Group	Yes	
ACES Standards Collaborators	Yes	We agree with the retirement of the above mentioned standards.
Peak Reliability	Yes	
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Ccompanies	Yes	

Organization	Yes or No	Question 10 Comment
Seminole Electric Cooperative, Inc.	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	ATC agrees with the retirement of the Requirements of the noted IRO Standards applicable to its registered functions as identified on the Mapping Document.
PNMR	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Liberty Electric Power, LLC	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 10 Comment
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	We agree with the retirement of the above mentioned standards.
Salt River Project	Yes	
NV Energy	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your response.		

11. **The mapping document posted on the project page explains how the drafting team believes Requirements from 5 TOP standards and 1 PER standard that are proposed for retirement are addressed without creating any reliability gaps. Do you agree with the retirement of standards TOP-004-2, TOP-005-2a, TOP-006-3, TOP-007-0, TOP-008-1, and PER-001-0? If not, why not? Please be specific.**

Summary Consideration: No changes were made to any proposed requirements due to industry comments as most comments were concerned about the mapping of the original requirements to the new proposed standards. Several references have been corrected in the mapping document as a result.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council	No	We do not agree with retiring PER-001 R1. This requirement requires operating personnel to have the authority to shed load without consulting non-operating management personnel. There have been instances where load shedding was delayed by non-operating managers or attempts to seek permission to shed load. The System Operator is responsible for maintaining a reliable system in Real-time and they should have full authority to shed load. The SDT reference to the FERC Order does not apply to PER-001. We do not agree with retiring TOP-002 R19. R19 requires the TOP to have an accurate model. The Planning Coordinator model may not be suitable for operations. There are scripts that can convert the Planning model into an Operations model, but these are not uniformly available. The new requirements for conducting an Operating Planning assessment and Real Time Assessment imply that operations has an accurate model. Referring to MOD-033 does not properly support retirement. MOD-033 places a requirement on the PC to have a model but does not require the PC to provide it to the TOP. The question of who is responsible for accuracy of the Real-time model is not answered in MOD-033. The fact that the TOP has to provide behavior data to the PC does not mean it has an accurate model. Agree with retiring TOP-004 R5 requiring remaining connected to the Grid, but suggest the justification is in the proposed TOP-0013 R14 and R15.

Organization	Yes or No	Question 11 Comment
		Agree with retiring TOP-006 R4 but do not agree with the justification pointing to TOP-003. TOP-006 R4 requires a load forecast to be completed for Operational Planning. The justification states this, but it should point to Operational Planning TOP-002-4 R1 and R2. Agree with retiring TOP-006 R6 but do not agree with the justification pointing to BAL-005 frequency metering. TOP's monitor line flows, voltages, SOL and IROL. These items have nothing to do with BAL standards. This requirement sets the stage for situational awareness and monitoring tools. The better reference is TOP-001 R10 which requires the TOP to monitor.

Response: PER-001 R1**:** Whether or not an entity provides its operating personnel with the responsibility and authority to implement Real-time actions, the entity, not the personnel, is subject to standards and requirements for specific actions to maintain reliable system operating conditions. For example, refer to approved EOP-002-3.1 Requirement R1, approved EOP-003-2 Requirements R6 and R8, and the proposed TOP-001-3 Requirements R1 and R2. No change made.

TOP-002 R19: The SDT would point out that there is not a similar requirement applicable to the Reliability Coordinators to maintain accurate computer models, yet none have been proposed, nor have any reliability issues been attributed to the lack of such a requirement. After referring to the Application Guidelines developed along with approved MOD-033-1, the SDT also acknowledges the impracticality of attempting to define what an accurate computer model is or how to measure it. However, the SDT believes that through Good Utility Practices and the application of the requirements in the proposed TOP and IRO Standards which require Transmission Operators and Reliability Coordinators to perform overlapping Operational Planning Assessments and Real-time Assessments and sharing results that this will help to identify modeling issues. No change made.

TOP-004 R5**:** The SDT agrees and the Mapping Document will be revised to refer to proposed TOP-001-3 Requirements R14 and R15.

TOP-006 R4: Approved TOP-006-3 Requirement R4 actually only requires information to be available, much like proposed TOP-003-3 Requirements R1 and R2 require a specification for necessary data. Proposed TOP-002-4 Requirements R1 and R2 require the application of that information through an Operational Planning Analysis. No change made.

TOP-006 R6: Rather than continuing the use of vague, undefined, and immeasurable terms such as sufficient, suitable, accurate, and timely, as used in approved TOP-006-3 Requirement R6, the SDT believes that this subject is adequately addressed by proposed TOP-001-3 Requirements R10 and R11 which require Transmission Operators and Balancing Authorities to monitor their respective areas. Standards referenced in the Mapping Document will be revised to include proposed TOP-001-3. No change made.

Organization	Yes or No	Question 11 Comment
Duke Energy	No	Until the proposed language is significantly modified and we are comfortable with those modifications, it is difficult for Duke Energy to determine if any reliability gaps exist with the recommended retirement of the 5 TOP standards and 1 PER standard that are proposed for retirement.
Response: Thank you for your response.		
SPP Standards Review Group	No	With the retirement of Requirement R1 of PER-001-0.2, the requirement for operating personnel to have the responsibility and authority to operate to maintain the reliability of the BES is eliminated. Such action reverts to conditions pre-1965 and the Northeast blackout. Do we as an industry feel this is where we need to be at this time? Where does that responsibility and authority lie following retirement? Is this captured in other requirements in the standards? If so, which ones?
Response: Whether or not an entity provides its operating personnel with the responsibility and authority to implement Real-time actions, the entity, not the personnel, is subject to standards and requirements for specific actions to maintain reliable system operating conditions. For example, refer to approved EOP-002-3.1 Requirement R1, approved EOP-003-2 Requirements R6 and R8, and the proposed TOP-001-3 Requirements R1 and R2. No change made.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	We agree with all the proposed retirements except TOP-004-2, Requirement R4.R4 stipulates that "If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes." While the intent is covered by the revised definition for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, neither definitions specifically ask for the verification of existing SOLs/IROLs or the determination of valid SOLs/IROLs as system condition changes go beyond the conditions covered by previous SOL/IROL calculations. Requirement R4 thus should be retained (and mapped into TOP-001-3) unless the two definitions are revised to require the

Organization	Yes or No	Question 11 Comment
		verification/determination of SOLs/IROLs through Operational Planning Analysis and Real-time Assessment. Not retaining R4, or without changing the definitions for the two terms, a responsible entity may project or enter an unknown state (for which valid SOLs/IROLs may not exist). An Operational Planning Analysis and Real-time Assessment at this time may indicate expected system performance, which may be unacceptable from an equipment loading, voltage level or stability viewpoint, but still there exist no SOLs/IROLs as a target to guide the responsible entity to adjust the BES to arrive at an acceptable state.
Response: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made.		
Electric Reliability Council of Texas, Inc.	No	TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.

Organization	Yes or No	Question 11 Comment
Response: TOP-006 R6**:** Revisions to the BAL Standards are outside of the scope of this SDT. However, rather than continuing the use of vague, undefined, and immeasurable terms such as sufficient, suitable, accurate, and timely, as used in approved TOP-006-3 Requirement R6, the SDT believes that this subject is adequately addressed by proposed TOP-001-3 Requirements R10 and R11 which require Transmission Operators and Balancing Authorities to monitor their respective areas. Standards referenced in the Mapping Document will be revised to include proposed TOP-001-3. No other change made. TOP-004 R6.2: Although proposed TOP-001-3 Requirement R8 is cited individually in the Mapping Document as the replacement for proposed TOP-004-2 Requirement R6.2, the proposed standards do not limit the coordination to a subset, but rather increases the level of coordination through requirements for formal outage coordination between Reliability Coordinators and Transmission Operators. As a whole, if the standards are followed, outage coordination as well as Operational Planning Assessments should identify all potential adverse impacts. Proposed TOP-001-3 Requirement R8 is from the Transmission Operators perspective and proposed IRO-008-2 is from the Reliability Coordinator's perspective. Combined, these actions are designed to thoroughly review planned operations and therefore accomplish the coordination that was vaguely referred to as coordination of switching transmission elements. No change made. TOP-002 R19: The SDT would point out that there is not a similar requirement applicable to the Reliability Coordinators to maintain accurate computer models, yet none have been proposed, nor have any reliability issues been attributed to the lack of such a requirement. After referring to the Application Guidelines developed along with approved MOD-033-1, the SDT also acknowledges the impracticality of attempting to define what an accurate computer model is or how to measure it. However, the SDT believes that through Good Utility Practices and the application of the requirements in the proposed TOP and IRO Standards which require Transmission Operators and Reliability Coordinators to perform overlapping Operational Planning Assessments and Real-time Assessments and sharing results that this will help to identify modeling issues. No change made.		
Peak Reliability	Yes	TOP-004 R5 - The requirement being retired deals with separation, but the mapping document references load shed language from the Functional Model. Separation may occur without load shed, so it is not clear that the coordination of separation is completely covered. TOP-008 R1 - The requirement being retired has the language "or contributing to an IROL or SOL violation", and the requirements in the mapping document may be missing coverage for SOLs outside of the TOPs area.

Organization	Yes or No	Question 11 Comment
Response: TOP-004 R5: Extreme operator actions such as separating from the interconnection would be coordinated under the proposed TOP-001-3 Requirements R14 and R15. The Mapping Document will be revised to refer to proposed TOP-001-3 Requirements R14 and R15. TOP-008 R1: Proposed TOP-001-3 Requirements R12 and R14 are not limited to SOLs or IROLs inside the Transmission Operators Area. If the identified exceedance is in another area and not identified by the contributing Transmission Operator, then Operating Instructions could be issued by the applicable Reliability Coordinator to instruct the Transmission Operator to take immediate steps to relieve the condition, which may include shedding firm Load. No change made.		
Idaho Power	Yes	I do not have a problem with TOP-003-3 but feel it should be combined with IRO-010-2 as the requirements are basically the same only the applicability is different. Combining the two standards would be best. The best solution would be to have a clearing house for all the data. The BA would submit the data to the RC on behalf of the TOP & GOP and it would be available for all other BA's.
Response: The SDT purposely kept proposed IRO-010-2 and proposed TOP-003-3 separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO-010-2 and Transmission Operators and Balancing Authorities for proposed TOP-003-3. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports comments posted by the SERC OC Work Group
FRCC Operating Committee (Member Services)	Yes	

Organization	Yes or No	Question 11 Comment
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SERC OC Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
PPL NERC Registered Affiliates	Yes	
FirstEnergy	Yes	
ACES Standards Collaborators	Yes	We agree with the retirement of the above mentioned standards.

Organization	Yes or No	Question 11 Comment
Bonneville Power Administration	Yes	
Georgia System Operations	Yes	
Rayburn Country Electric Cooperative	Yes	
CenterPoint Energy Houston Electric LLC.	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Manitoba Hydro	Yes	
Exelon Companies	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Ingleside Cogeneration LP	Yes	
Xcel Energy	Yes	
American Transmission Company	Yes	ATC agrees with the retirement of the Requirements of the noted TOP Standards applicable to its registered functions as identified on the Mapping Document.
PNMR	Yes	

Organization	Yes or No	Question 11 Comment
David Kiguel	Yes	
PJM Interconnection	Yes	
Austin Energy	Yes	
Consumers Energy	Yes	
Liberty Electric Power, LLC	Yes	
Oncor Electric Delivery LLC	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
INDN - Independence Power & Light	Yes	
Georgia Transmission Corporation	Yes	We agree with the retirement of the above mentioned standards.
Salt River Project	Yes	
NV Energy	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your response.		

12. **The SDT is seeking input on whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators. Please explain what you feel the correct periodicity and supply technical rationale for your suggestion.**

Summary Consideration: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including approved EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards noted, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan.

Finally, the standard does not mandate a specific toolset required to perform a Reliability Assessment nor does it specify the type of evaluation that has to be performed when tools are unavailable. The SDT expects that some type of evaluation is performed at least every 30 minutes regardless of capability availability. However, the SDT feels that the definition of Real-time Assessment along with the changes made to the requirement language, provide flexibility and allows for other types of evaluation methods for periods where normal tools are unavailable or during EMS failures. The SDT feels that is important for entities to recognize the need for situational awareness even during periods where primary systems are unavailable.

The SDT made the following changes due to industry comments:

Proposed TOP-001-3, Requirement R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Organization	Yes or No	Question 12 Comment
Duke Energy	No	While Duke Energy agrees, in general, that a Reliability Assessment shall be performed at least once every 30 minutes, we have concerns with this zero tolerance requirement. We believe a provision that allows for a defense in depth strategy is needed to allow the RC and/or TOP to develop a plan, process, or procedure for those instance where various tool(s) used to conduct the Reliability Assessment are unavailable for longer than 30 minutes. This would align with NERC's transition to the RAI Initiative. In addition, EOP-008-1 R1.5 allows a transition period of less than or equal to 2 hours for a RC and/or TOP to transition to its backup control center. If a RC and/or TOP is in its transition phase and it takes longer than 30 minutes to become fully implemented, would the RC and/or TOP violate R13 of this requirement? It could take longer than 30 minutes for an entity to arrive at the backup control center for various reasons. This is one of the reasons why a defense in depth strategy is needed in this requirement.
PJM Interconnection	Yes	PJM supports the 30 minute periodicity. Specific to IRO-008-2, R5, PJM is concerned with the compliance overlap and potential non-compliance with EOP-008, R5 which provides for a two hour timeframe to have the back-up facility fully functional. PJM recommends the addition of language in IRO-008-2, R5 to provide relief to the RC for the period when evacuation to the back-up facility is necessary and the timeframe it takes for the back-up control center to be fully functioning. Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that 30 minutes is the correct periodicity for normal operations. There should be flexibility in the requirement to account for instances when analysis tools may be unavailable temporarily recognizing the balancing of time to both trying to make the tools available again and or taking alternative means of conducting a Real Time Assessment. Recommendation could be to amend the requirement

Organization	Yes or No	Question 12 Comment
		allowing for notification to affected entities and taking alternative actions to conduct a Real Time Assessment within 60 minutes of the last RTA.
NV Energy	No	As noted in comments to prior questions, the 30 minute periodicity is inappropriate. As noted earlier, we believe that the intent here should be that the Operator has situational awareness, not that one meets a quota of RTA executions. The 30 minute period is also in conflict with certain EOP requirements which allow up to 2 hours to reestablish control center functionality. Further, a 30 minute requirement would almost necessitate backup means of conducting RTAs, as there is little tolerance for a failure of the tools.

Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.

The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address:

- **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
- **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or

Organization	Yes or No	Question 12 Comment
even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision.		
Bonneville Power Administration	No	BPA proposes 60 minutes as the correct periodicity. This allows time to set up, run and analyze the results of studies, especially if stability analyses must be performed.
SPP Standards Review Group INDN - Independence Power & Light		We tend to lean toward a not so prescriptive quantitative time limit but toward a more practical justification for why the assessment is needed. It can be dependent upon current system conditions where during light load conditions Real-time Assessments may not be needed as frequently as they are during peak load conditions. Even this can be different from system to system. Some may encounter congestion during light load periods and others may not. It's too dependent on too many variables. We feel that consideration should be given to situations like this rather than a one-size fits all 30-minute rule.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability.. No change made.		
MidAmerican Energy	No	See comments provided under TOP-001.
Response: See response to comments for TOP-001.		
ACES Standards Collaborators	Yes	We understand the rationale for using 30 minutes for performing Real-time Assessments and believe it is sufficient. We ask the SDT to clarify that registered

Organization	Yes or No	Question 12 Comment
		entities are not required to install real-time state estimation to perform its Real-time Assessments.
Response: The Standard does not mandate a specific toolset required to perform a Reliability Assessment.		
Peak Reliability	Yes	Peak Reliability believes this timeframe to be sufficient as long as the 30 minutes is under normal operating conditions (when tools are working as expected). However, IRO-008-2 R5 needs to be revised to include language allowing for tool outages. What is the SDT's expectation of performing Real-Time Assessments when tools are unavailable due to unforeseen tool outages?
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The Standard does not mandate a specific toolset required to perform a Reliability Assessment nor does it specify the type of evaluation that has to be performed when tools are unavailable. The SDT expects that some type of evaluation is performed at least every 30 minutes regardless of tool availability. However, the SDT feels that the definition does provide the flexibility needed by the		

Organization	Yes or No	Question 12 Comment
industry to determine the type and manner of evaluation or other procedural backstop process to support a Real-time evaluation even after unforeseen tool failures.		
Independent Electricity System Operator	Yes	We agree with the 30 minute time frame. Further, we suggest the standard be strengthened to ask for developing SOLs and IROLs within 30 minute if there does not exist any predetermined or valid limits for the conditions being analyzed. This is particularly important when, for example, an entity has valid SOLs and IROLs for a set of system and operating conditions but an unplanned event that takes out some BES Facilities from service, rendering the previously developed SOLs/IROLs not valid. In this case, the responsible entity needs to recalculate the SOLs/IROLs for the new condition. A 30-minute is the appropriate time frame for the recalculation. The standard should specifically require that SOLs/IROLs be reestablished within this period.
Response: The SDT believes that operation to SOL/IROL(s) should be inherent to any Real-time Assessment process. However, the SDT feels that mandating the development of SOL/IROL(s) under outage conditions is better addressed as part of the SOL Methodology and the requirement to ensure BES performance consistent with approved FAC-011-2. The proposed definition/requirement does not prohibit an entity from developing SOL/IROL(s) in real-time based on unplanned events. No change made.		
Northeast Power Coordinating Council		30 minutes is appropriate and consistent with the current NERC EAP guidelines for monitoring and control functionality under normal operating conditions. However, exceptions need to be afforded for EMS system failures and unplanned Control Center outages and/or evacuations, or system blackout, e.g., Hurricanes Katrina, Ike, and Sandy, 2003 Northeast Blackout, 2012 Southwest Blackout. See EOP-004-2 - Attachment 1, Standard EOP-008-1 - Loss of Control Center Functionality, Standard COM-001-2 - Communications (R9), Standard EOP-005-2 - System Restoration from Blackstart Resources, Standard EOP-008-1 - Loss of Control Center Functionality.
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-		

Organization	Yes or No	Question 12 Comment
3. Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The SDT recognizes that the 30-minute timing requirement must be coordinated with an entity's Loss of Control Center Functionality Operating Plan. The SDT believes that the proposed TOP-001-3, IRO-008-2 and approved EOP-008-1 requirements in question are in agreement with a common concept to ensure System Operators have situational awareness of the BES at all times. This obligation includes identification of any mitigating actions and functional requirements associated with the Real-time Assessment requirement during the transition to fully implement the backup functionality as part of an entity's Loss of Control Center Functionality Operating Plan. Specifically, approved EOP-008-1 requirements address: · **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES. · **1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. The requirement does not mandate a specific tool, such as RTCA, and does not imply a zero-defect requirement for the analysis tool. The 30-minute requirement and the definition of "Real Time Assessment" does not specify the manner in which an assessment is performed nor does it preclude Reliability Coordinators and Transmission Operators from taking "alternative actions" and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on the Reliability Coordinator to perform a Real-time Assessment or even review their Reliability Coordinator's Contingency analysis results when their capabilities are unavailable and vice-versa. The SDT did modify the requirement language to change "shall perform a Real-Time Assessment" to "shall ensure a Real-time Assessment is performed" to increase the flexibility on who can perform a Real-time Assessment and determined that the modified language is sufficient to coordinate with the existing requirements of approved EOP-008-1 and should not introduce any requirement timing conflicts. The SDT has clarified the language of Requirement R10. See summary consideration for revision. The definition of Real-Time Assessment provides flexibility and allows for other types of evaluation methods for periods where normal tools are unavailable or during EMS failures. The SDT feels that is important for entities to recognize the need for situation awareness even during periods where primary monitoring systems are unavailable.		
Dominion		Dominion believes that the required periodicity for the performance of Real-time Assessments should be at least once every ten minutes. This is the periodicity that

Organization	Yes or No	Question 12 Comment
		NERC required MISO and First Energy to meet following the August 14, 2003 blackout. See page 152 of the Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004
Response: The SDT does not agree with increasing the required periodicity to 10 minutes. The SDT believes that the 30-minute Reliability Assessment timing requirement is a minimum requirement during normal operations and is intended to accommodate the different types of operating models within the industry while promoting consistent monitoring practices across the Interconnections. The proposed requirement does not prohibit entities from performing more frequent analysis as system conditions warrant. The SDT expects that some entities do, and will continue to, perform assessments on a more frequent basis depending on the systems and potential impacts to BES reliability. No change made.		
Idaho Power		The 30 minute time seems to be an arbitrary value. Real-time Assessments need to be done as system conditions change; load or interchange changed by XXX MW's or system topology changes would seem to be a more logical trigger. That said a specific time frame of 30 minutes, 45 minutes or 1 hour would be easier to audit. Inaccurate assessments that have been rushed in order to meet a compliance standard can have extreme adverse impact on reliability.
Response: The SDT recognizes the concern that depending on the toolset, the level of effort to perform a Real-time Assessment could be impacted by the magnitude of the changes to system conditions. The effort required to perform a Real-time Assessment during timeframes with minimal change may be nothing more than reviewing/updating a previous Real-time Assessment. The SDT feels that is important for entities to recognize the need for situation awareness during all operating periods. Processes must be established to ensure Real-time Assessments are accurate, especially during timeframes of rapidly changing system conditions or sudden topology changes. No change made.		
Oncor Electric Delivery LLC		As previously stated in response to Question 7, Oncor considers Real-time Assessments to be a Reliability Coordinator function. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. Requiring Transmission Operators to replicate Real-time Assessments currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added

Organization	Yes or No	Question 12 Comment
		reliability to the BES. Oncor requests the SDT consider the applicability before responding to the periodicity.
Response: The SDT did discuss implications of the applicability; however it found that the definition is consistent with currently approved requirements for Transmission Operators. As an example, approved TOP-004-2 requires Transmission Operators to ensure that the transmission system is operated so that instability, uncontrolled separation, or Cascading outages will not occur as a result of the most severe single Contingency. A Real-time Assessment must be performed to ensure BES facilities are N-1 secure. No change made.		
Texas Reliability Entity		SDT, please consider that a different periodicity may be required depending on the tools used to perform Real-time Assessments. In the ERCOT region, some of the tools used for performing Real-time Assessments only run once every 30 minutes. Since SOLs, by definition, include voltage and transient stability ratings, this implies that the stability analysis should be conducted at least once every 30 minutes. If the tool fails to solve or fails to converge during one of these runs, would that constitute a violation of this requirement? If State Estimator or Contingency Analysis tools are unavailable for 30 minutes or more (i.e. currently a reportable event under the NERC Events Analysis program category 1h), would that constitute a violation of this requirement?
Response: The SDT evaluated the 30-minute requirement at length and came to the conclusion that the 30-minute timeline is consistent with currently approved standards including EOP-004-2, IRO-001-1.1, IRO-008-1, TOP-004-2, TOP-007-0, and VAR-001-3 Based on the current standards in place, industry feedback from this posting and without additional technical rationale for deviating from the intent of the approved standards above, the SDT felt the 30-minute criteria remains appropriate and important to maintaining BES reliability. The definition/requirement does not mandate the specific toolset or process to perform the evaluation and therefore allows entities flexibility in how an evaluation is performed given the potential operating scenarios and/or normal monitoring tool failures. No change made. The SDT is not permitted to respond to questions about potential compliance.		

Organization	Yes or No	Question 12 Comment
Arizona Public Service Company	Yes	We agree with the 30 minute periodicity
FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	No Comments
CenterPoint Energy Houston Electric LLC.	Yes	CenterPoint Energy agrees with 30 minutes being the correct periodicity for performing Real-time Assessments.
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole agrees with 30 minutes
Xcel Energy	Yes	
American Transmission Company	Yes	ATC has no comment whether 30 minutes is the correct periodicity for the performance of Real-time Assessments for Reliability Coordinators and Transmission Operators.
David Kiguel	Yes	Agree with the 30 minutes periodicity.
Consumers Energy	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 12 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Florida Municipal Power Agency		FMPA agrees with 30 minutes as a minimum periodicity for Real-time Assessments.
Response: Thank you for your response.		

13. Do you have any comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: Most of the comments were requesting clarification on a specific item or term or suggesting slight changes to provide additional clarification. Changes were made to the SOL whitepaper to address industry comments. A red-lined version of the whitepaper is available as a separate document on the project web site.

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	Yes	The SOL Whitepaper provides a good example of evaluating system performance. However, it implies that the continuous thermal rating is a hard limit. A Rating Authority may establish applicable pre-contingency thermal limits that are higher than the continuous rating under specific circumstances and do not result in equipment damage. The acceptable pre-contingency performance defined on page 2, item (b) can be written as "All Facilities shall be within their pre-Contingency thermal limits" rather than "All Facilities shall be within their Normal (continuous) Facility Ratings and thermal limits." This is consistent with the methodology for voltage limits listed on page 2, item (c).From an operational perspective, it is not practical to cover any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operating plans must protect against that. Operationally you need to protect against the loss of units regardless of cause.
Response: The SDT chose to retain the “Normal” limit to ensure consistency with approved FAC-008-3. The whitepaper use of the term “instability” is consistent with the NERC definition of SOL as well as approved FAC-011-2 for the operations horizon, which requires all applicable entities to demonstrate transient, dynamic, and voltage Stability following defined Contingencies. The SDT struck the parenthetical “continuous” language throughout the whitepaper.		
ACES Standards Collaborators	Yes	(1) If the drafting team has identified “much confusion with - and many widely varied interpretations and applications of - the SOL term,” then why not revise the definition of SOL in the NERC glossary? The whitepaper provides clarification, but this

Organization	Yes or No	Question 13 Comment
		document may be lost over time. We recommend that the drafting team discuss revisions to the glossary term to determine if additional clarity can be provided.
Response: The SDT considered modifying the existing SOL definition but came to the conclusion that the definition could not be modified in a concise manner. The SDT believed that a better approach would be to provide a whitepaper including examples. The SDT intends to incorporate industry comment into the whitepaper and incorporate the whitepaper as an Appendix to proposed TOP-001-3. The SDT encourages the industry to pursue redefining SOL and IROL through the SAR process if it is deemed necessary or appropriate. No change made.		
ISO/RTO Standards Review Committee (SRC)	Yes	From an operational perspective, we do not believe it is practical to cover for any and all unit instability issues which may remain local in nature. We agree that, to the extent unit instability would cascade into system instability, operation plans must protect against that. We also have a concern over the actions depicted for the Emergency (4 hr.) condition in the example in Table 1.When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with the time on which the applicable emergency rating is based (e.g. 30 or 15 minutes) to reduce flow within the applicable rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency rating consistent with timelines identified in Operating Plan. The "as necessary and appropriate" qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the Emergency rating.

Organization	Yes or No	Question 13 Comment
Response: The whitepaper use of the term "instability" is consistent with the NERC definition of SOL as well as approved FAC-011-2, which require all applicable entities to demonstrate transient, dynamic, and voltage Stability following defined Contingencies. No change made. The SDT agrees and has modified the whitepaper to include the qualifier "as necessary and appropriate". See redlined whitepaper for revisions.		
Peak Reliability	Yes	Comment 1 - the SOL performance summary states that it is acceptable to operate above the highest available limit post-contingency as long as "the entities operating plan address potential impacts and mitigating strategies to ensure potential impact is localized." Post-contingency exceedance of the highest available limit should not be allowed unless there are no viable pre-contingency actions short of load shed, AND the impact of the contingency is known to be contained. Comment 2 - Operating plan example table uses the term "load shed" to describe a facility rating. This sounds like it came from Alstom data base naming conventions, but may result in confusion and should be changed.
Response: The SDT agrees that "Post-contingency exceedance of the highest available limit should not be allowed unless there are no viable pre-contingency actions short of load shed and the impact of the contingency is known to be contained." The SDT has provided clarification within the whitepaper. See redlined whitepaper for revisions. Approved FAC-008-3 allows for more than one "Emergency Rating". The SDT modified the whitepaper to remove "Load Shed" rating to ensure terminology consistent with approved FAC-008-3. See redlined whitepaper for revisions.		
Bonneville Power Administration	Yes	Since entities will need to accurately interpret several requirements in the Standard, BPA suggests adding the System Operating Limit (SOL) Definition and Exceedance Clarification white paper to the TOP-001-3 Standard as an appendix.
Response: The SDT intends to add the whitepaper as an appendix to the proposed TOP-001-3.		

Organization	Yes or No	Question 13 Comment
CenterPoint Energy Houston Electric LLC.	Yes	At a high level, CenterPoint Energy supports the SOL Exceedance White Paper; however, the Company has concerns regarding two main issues identified below. 1) SOL Performance Summary Chart (Page 4): The ERCOT Region operates such that the continuous Pre-Contingency flow never exceeds the 24hr rating. For reliability purposes, CenterPoint Energy believes Pre-Contingency flow in any range above the 24hr rating is not acceptable and recommends the SDT revise the chart accordingly. 2) Steady State Voltage Limit Exceedance (Page 5): The second sentence states, "Both normal and emergency voltage limits are established that respect the Transmission Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3." CenterPoint Energy does not agree that normal and emergency voltage limits are established using the Facility Ratings Methodology required in FAC-008-3. For example, FAC-008-3 R8.2 refers specifically to a Thermal Rating. Additionally, the NERC definitions of Normal and Emergency Ratings refer to "electrical loading, usually expressed in megawatts..." which indicates a Thermal Rating. While CenterPoint Energy agrees that normal and emergency voltage limits are established, it is through other means outside of FAC-008-3; therefore, CenterPoint Energy recommends removing this sentence.

Response: The chart is indicative of minimum acceptable system performance. While entities may choose to adopt a more rigorous approach to pre-Contingency exceedance of Facility Ratings, the SDT believes that the minimum level of acceptable pre-Contingency performance occurs when a Facility Rating is exceeded for an unacceptable time duration – not when it is exceeded at all. An entity's Operating Plan addresses scenarios when Load shed is required pre-Contingency. No change made.

The NERC definition of Facility Rating includes "maximum and minimum voltage". The SDT believes that approved FAC-008-2 does not prevent Transmission Owners and Generator Owners from including voltage limitations within the scope of the Facility Ratings Methodology document if the Transmission Owner or Generator Owner chooses to do so. Approved FAC-008-2 frequently speaks to "equipment ratings" and "manufacturer's specifications", which can include voltage limitations. If a Transmission Owner or Generator Owner's Facility Ratings Methodology includes voltage limitations, then the voltage limits determined by the Transmission Operator need to respect those limitations. The SDT did not remove the reference to the Transmission Owner's and Generator Owner's Facility Ratings Methodology with reference to voltage limits; however, the SDT did change the language to say: "Normal

Organization	Yes or No	Question 13 Comment
and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission Owner or the Generation Owner’s Facility Ratings Methodology per approved FAC-008-3.” See redlined whitepaper for revisions.		
Volkmann Consulting	Yes	Figure 1 on page 4 suggests that the TOP is allowed to risk a post contingency exceedance of the short term emergency (STE) rating if there is an Operating Plan. This is a dangerous reliability risk. An Operating Plan should not be an acceptable means to exceed the STE, unless that Transmission Owner's Facility Rating Methodology allows it and agrees to a new STE. The new STE must factor in the response time of the Operating Plan. As stated the document suggests that the Operating Plan can be used with no limitations of exceeding the STE.
Response: The SDT agrees. However, the SDT does not want to set the expectation that Load must be shed pre-Contingency whenever tools indicate an operating condition where a Contingency will cause a Facility to exceed its STE. While the SDT expects entities to take pre-Contingency steps to relieve the condition (including re-dispatch, reconfiguration, and making adjustments to the uses of the Transmission system), the issue of “when to shed Load pre-Contingency” is expected to be addressed in the Operating Plan. An entities Operating Plan will define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure, consistent with the purpose of SOL Methodologies. The SDT has provided additional clarification within the whitepaper. See redlined whitepaper for revisions.		
David Kiguel	Yes	Intent is correct. Could better explain some concepts like for example when short time ratings could be exceeded in pre-contingency.
Response: The SDT has revised the whitepaper to provide additional clarification on this topic. See redlined whitepaper for revisions.		
Electric Reliability Council of Texas, Inc.	Yes	Table 1 identifies trending/monitoring and non-cost actions to prevent contingency from exceeding emergency limit. Some entities may only alarm/trend/monitor when post-contingency loading approaches within a threshold or exceeds the emergency limit. This minimizes unnecessary attention to post-contingency loading that an operator has sufficient time to reduce loading if the contingency were to occur. Transient instability (angular, un-damped oscillations) can be in addition to voltage instability, be local instability limits and not qualify as an IROL.

Organization	Yes or No	Question 13 Comment
Response: The SDT agrees with the assessment of alarm/trend/monitor, however, the SDT encourages entities to alarm at a threshold below the emergency limit to ensure System Operators have sufficient time to proactively address facility loadings. The SDT agrees that IROL facilities are a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s), or cascading outages and are not localized in nature. No change made.		
PNMR		Figure 2 of the whitepaper depicts a PV plot and is used to demonstrate the definition of an IROL. PNMR finds this figure to be confusing. The figure defines the IROL as the “knee” on the PV plot. In WECC the path SOL may be a value less than the “knee” of a PV curve. Does the figure imply that all voltage stability SOLs also have an IROL? Can only path voltage stability and voltage SOLs have IROLs? PNMR would recommend clarifications be added to the whitepaper to resolve these questions.
Response: While the SDT cannot comment on WECC specific concepts such as the “path SOL”, the SDT believes that SOL exceedance is generally characterized by the exceedance of Facility Ratings or voltage limits. To the extent that exceeding an SOL could result in wide-area impacts such as cascading, uncontrolled separation, or uncontained instability, that facility would also have an IROL. The SDT does not believe that all Stability issues are automatically IROLs. As stated in the whitepaper, a localized voltage collapse may not qualify as an IROL. No change made.		
Independent Electricity System Operator	No	We generally agree with the White Paper except the actions depicted for the Emergency (4 hr.) condition in the example in Table 1.When power flow on a Facility exceeds the 4-hour rating, an entity would take all available actions except load shedding to reduce flow to below the 4-hour rating. If the projected loading exceeds the Emergency rating of the concerned (limiting) Facility, load shedding may not be implemented but rather, can be implemented when the critical contingency occurs providing that the load shedding action can be implemented with 15 minutes or less to reduce flow within the 15-minute or 4-hour rating. In other words, an entity may not shed load for the sake of avoiding shedding load if and when a contingency occurs. We suggest to revise the example to: All of the above, plus load shed as necessary and appropriate, to control violation below Emergency Rating consistent with timelines identified in Operating Plan. The “as necessary and appropriate”

Organization	Yes or No	Question 13 Comment
		qualifier will allow and entity to assess if load shedding post-contingency can be implemented in time to avoid exceeding the 15-minute rating.
Response: The SDT has revised the whitepaper to include “as necessary and appropriate”. See redlined whitepaper for revisions.		
Duke Energy	No	1. Duke Energy disagrees with the idea that every exceedance of a facility rating is an SOL(s) as indicated in the White Paper. We would also like to point out that this premise is not reflected in the currently enforceable Reliability Standards. Also, it appears as though the authors of the White Paper may have inadvertently over-complicated their explanation of what constitutes an SOL. We believe that the use of the term “actual flow” in place of Pre-Contingency would help improve the clarity of the examples given throughout the White Paper. 2. Figure 1 on page 4: The table appears to be more restrictive at lower loading levels than it is at higher loading levels, and it also appears to be in conflict with the Operating Plan found on the next page with regard to Load Shedding. 3. We also suggest adding language stating, that “unless the entity’s Operating Plan addresses potential impacts and mitigating strategies to ensure potential impact is localized” at the end of the fourth and sixth bullets in Figure 1, this would improve the consistency. 4. Steady State Voltage Limit Exceedance: We suggest striking the “or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event” from the paragraph. We feel that there could be auto-reactive supplies that may be available to bring the limit back to an acceptable range, also, a Real-time Assessment/situational awareness tool is designed to aid in managing the system and not designed to create exceedances and violations. 5. Also, we suggest that a clause be inserted taking into account automatic or manual control of reactive resources that are accepted per FAC-011 for SOL(s). Ultimately, we feel that SOL performance is based on flows in Real-time, and that is the criteria that should be used to determine if you have exceeded or not exceeded.

Organization	Yes or No	Question 13 Comment
		6. Stability Limit Exceedance: The first sentence of paragraph 4 which states, "SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability" appears to redefine what is considered an SOL exceedance. An SOL is supposed to have a value associated with it, and you exceed the SOL when you cross that value. The above referenced sentence describes an SOL exceedance as entering into an Operating space and then what the next contingency could result in. We feel that this language is not consistent with the definition of an SOL. 7. Figure 2: Duke Energy is concerned that the language in Figure 2 is expanding the concept of SOL Exceedance. Of particular concern is the phrase, "unacceptable system performance equates to SOL exceedance," we fail to see how one could monitor this or even apply it. 8. Also, we recommend the removal of bullets 2 and 4. It appears that bullet 4 is saying the same thing regarding voltage, as bullet2 is saying for facility ratings. 9. Lastly, bullets 1 and 3 are not "Assessments." We suggest them being in their own category, as SOL exceedance should be based on actual system conditions 10. SOL Exceedance and Operating Plan: Duke Energy is concerned that the language used in this section blurs the line on whether you have exceeded an SOL or not. As currently written, the section reads as though that even after you have exceeded an SOL, it may depend on what happens afterward to determine if it was an actual exceedance or not. With the actual exceedance in doubt, it is difficult to know where an entity is from a compliance standpoint. . 11. Table 1 Operating Plan Example: We request removal and replacement of the terms "Non-Cost" and "Off-Cost" with more common industry terms, or insert an explanation of the terms used. Also, the use of the terms "load shed" in the Pre- and Post-Contingency Loading columns is somewhat misleading. Consider revising to more clearly state the expectations regarding the use of Load Shed in this context.

Organization	Yes or No	Question 13 Comment
		Applicable Definitions: The term "Interchange" is used sporadically throughout the definitions section of the White Paper, we suggest changing to "known Interchange" for clarity. Also, we recommend removing the parenthetical at the end of Real-time Assessment and Operational Planning Analysis. Lastly, Phase Angle, Equipment Limitations, and Special Protection System should be listed as sub bullets as part of the Assessment, and not be a part of the definition.

Response:

1. The whitepaper attempts to clarify long-standing points of confusion – understanding what an SOL is, what it means to establish an SOL, and what it means to exceed an SOL by pointing directly to requirements contained within the approved FAC Standards. The SDT believes so long as Transmission Operators are following approved FAC-014-2, Requirement R2, there will be no inconsistencies between Reliability Coordinator and Transmission Operator monitored SOLs (page 2, bullet 3 of whitepaper). Individual Operating Plans, that recognize time-based rating methodologies, provide guidance to System Operators to ensure SOL exceedances are mitigated. No change made.
2. The SDT has reviewed the figure and table and does not agree with Duke's assertions. Figure 1 on page 4 is less restrictive at lower load levels and more restrictive at higher load levels as indicated by the decreasing mitigation time requirements as loading increases. The SDT made changes to the body of the whitepaper and to the second bullet in Figure 1, to address the Load shed issue. The revised whitepaper states that "An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring BES remains N-1 secure."
3. The SDT believes the bullets are correct and complete. Duke's suggested language applies only to the second bullet and does not apply to the 4th and 6th bullets. The Operating Plan should reflect whether pre- or post-Contingency action is required based the time based Facility Rating, available mitigation actions, the amount of time System Operators have to implement those actions. The whitepaper clarifies this issue with the added statement, "In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including re-dispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition.
4. The SDT believes that Real-time Assessments aid the System Operators in managing the system by determining whether or not SOLs are being exceeded in Real-time operations. It is common practice to have auto- reactive devices which ensure acceptable post-Contingency voltages. The SDT sees no conflict so long as the Real-time Assessment recognizes the impact of auto-reactive

Organization	Yes or No	Question 13 Comment
devices and those devices are sufficient to maintain voltages within acceptable limits. The SDT added the concept of auto-reactive devices as part of an assessment in determining SOL exceedances as per Duke's request. **5.** The SDT agrees that SOL performance is based Real-time flows and voltages, but considers both the pre- and post-Contingency operating states. This is described in the whitepaper. No change made. **6.** The SDT does not agree with Duke's comment. The SDT basis for the whitepaper was the NERC definition of SOL (first paragraph) and used the subsequent paragraphs of the whitepaper to tie various standard Requirements together in an effort to further define SOL exceedance for each component (thermal, voltage and stability). One component, Stability limits, are typically developed during the Operating or Planning Horizon, though they can also be determined in Real-time. Stability limits and mitigating strategies are provided to System Operators as part of an Operating Plan. Real-time Assessments are performed to ensure the system is operated in a state where the next Contingency does not result in instability (i.e., no SOL exceedance). No change made. **7.** The SDT believes the bullets that follow Figure 2 further define "unacceptable performance" or "SOL Exceedance" and that additional details would be contained within the entities Operating Plan, which provides System Operators details on how to monitor and mitigate potential SOL exceedances. No change made. **8.** The SDT chose to include separate bullets to clearly explain unacceptable performance for both pre- and post-Contingency thermal and voltage scenarios. No change made. **9.** The SDT chose to include separate bullets to clearly explain unacceptable performance for both pre- and post-Contingency thermal and voltage scenarios. A Real-time Assessment includes an analysis of actual flows/voltages even though the system may be more frequently limited on an N-1 basis. No change made. **10.** The SDT considered Duke's comments but were cautious of developing a "one size fits all" approach. The whitepaper intends to clarify when an SOL is being exceeded. The revised TOP standards requires System Operators take action to mitigate an SOL exceedance in accordance with their Operating Plan. The System Operators should follow the details of that entities Operating Plan to ensure that an exceedance does not result in a violation. No change made. **11.** The SDT has revised the whitepaper to provide additional clarification where required. See redlined whitepaper for revisions.		
SPP Standards Review Group	No	We have concerns with the implications in the last paragraph on Page 2. The implication here is that a set of SOLs defined at some previous time may not be adequate to protect the reliability of the BES. We agree with this concept but believe the white paper needs to recognize the fact that the list of SOLs may not necessarily be stagnant. If this pre-defined listing is updated continuously in Real-time, it is a very

Organization	Yes or No	Question 13 Comment
		accurate representation of the limitations on the system at any given time. The white paper doesn't provide for this additional concept and should. Capitalize 'Real-time' in the 1st bullet at the top of Page 9. Also capitalize Bulk Electric System in the 2nd bullet. Delete the comma in the last line of the definition of Emergency Rating.
Response: The SDT agrees that SOLs are not stagnant and will change over time. The intent of the whitepaper is to provide clarity across the Interconnections, while still respecting that an individual entities SOL Methodology provides details that recognize the complexities of a regional electric grid. The SDT has revised the whitepaper to provide additional clarity. Additionally, the SDT has incorporated the suggested grammatical changes. See redlined whitepaper for revisions.		
FRCC Operating Committee (Member Services) Florida Municipal Power Agency Seminole Electric Cooperative, Inc.	No	Add language to the SOL Exceedance White Paper to state that a SOL can only be exceeded where it has been defined on a TOPs system as is stated in FAC-014-2. Add language to the SOL Exceedance White Paper clarifying that SOLs are only exceeded in Real-time based on actual system conditions and not as a result of the use Real-time assessment tools performing post-contingency analysis. Page 3 - Change the words "SOLs include Facility Ratings..." to "SOLs may be based on Facility Ratings..." Page 4 - SOL Performance Summary bullet 4. Add language "except load shed" to be consistent with operating plan in table 1. Page 8 - Typo in the Operating Procedure definition. The word "operating" should be "operator" in the last sentence.
Response: 1. The SDT believes that as long as Transmission Operators are following approved FAC-014-2, Requirement R2, there will be no inconsistencies between Reliability Coordinator and Transmission Operator monitored SOLs (page 2, bullet 3 of whitepaper). The SDT added language to clarify that SOL exceedance is based on Real-time Assessments.		

Organization	Yes or No	Question 13 Comment
2. The SDT believes that SOL exceedance is based on pre- or post-Contingency conditions, consistent with the acceptable system performance criteria described in approved FAC-011-2 Requirement R2. As stated in the whitepaper, unacceptable pre- or post-Contingency performance (as described in approved FAC-011-2 Requirement R2) equates to SOL exceedance. No change made. **3.** The SDT agrees and has revised the whitepaper accordingly. See redlined whitepaper for revisions. **4.** The SDT has revised the whitepaper to provide clarity on the Load shed issue. See redlined whitepaper for revisions. **5.** The SDT has revised the whitepaper to address the grammatical error. See redlined whitepaper for revisions.		
Consumers Energy	Yes	
Dominion	Yes	Dominion would like to state its support and agreement with this well written paper.
PacifiCorp	No	
Arizona Public Service Company	No	
Associated Electric Cooperative, Inc. - JRO00088	No	
MRO NERC Standards Review Forum	No	
Colorado Springs Utilities	No	
SERC OC Review Group	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi	No	

Organization	Yes or No	Question 13 Comment
Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
PPL NERC Registered Affiliates	No	
Georgia System Operations	No	
EDP Renewables North America LLC	No	
Manitoba Hydro	No	
Xcel Energy	No	
American Transmission Company	No	
Idaho Power	No	
PJM Interconnection	No	
Liberty Electric Power, LLC	No	
Oncor Electric Delivery LLC	No	
Tri-State Generation and Transmission Association, Inc.	No	

Organization	Yes or No	Question 13 Comment
INDN - Independence Power & Light	No	
Georgia Transmission Corporation	No	
Salt River Project	No	
MidAmerican Energy	No	
Response: Thank you for your response.		

14. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

Summary Consideration: The SDT made a number of changes due to industry comments.

Proposed IRO-001-4, Requirement R3, Severe VSL: The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the reasons shown in Requirement R2.

Proposed IRO-002-4, Requirement R2:

R2	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.

Proposed IRO-008-2: Data Retention - Each Reliability Coordinator shall each keep data or evidence for Requirement R5 and Measure M5 for a rolling 30 day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Proposed IRO-008-2, Requirement R1, Severe VSL: The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Reliability Coordinator will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).

Proposed IRO-008-2, Requirement R5:

IRO-008-2, R5	Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	The Reliability Coordinator did not perform Real-time Assessments. OR For any sample 24 hour period within the 30 day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for more than three 30-minute periods within that 24-hour period.

Proposed IRO-008-2, Requirement R7, Severe VSL: The Reliability Coordinator failed to issue Operating Instructions, as necessary, to ensure that actions were taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Proposed IRO-008-2, Requirement R8:

R8	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6

			Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the Emergency identified in Requirement R6 was prevented or mitigated	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement	was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated.

				R6 was prevented or mitigated	R6 was prevented or mitigated	

Proposed IRO-010-2, Requirement R1: The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

Proposed IRO-010-2, Requirement R1, Severe VSL (first part): The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed IRO-010-2, Requirement R2: The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. (Violation Risk Factor: Low) (Time Horizon: Operations Planning)

Proposed IRO-010-2, Requirement R2, VSL Table: For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.

Proposed IRO-010-2, Requirement R3:

R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the

			specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	documented specifications for data.

Proposed IRO-014-3, Requirement R2:

R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet one of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet two of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet all three of the criteria specified in Requirement R2.

Proposed IRO-014-3, Requirement R6, Severe VSL: The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.

Proposed IRO-017-1, Requirement R1:

R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing four or more of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement,

						and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Proposed TOP-001-3, Requirement R8:

R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that	The Transmission Operator did not inform two other known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is less, of its actual or expected	The Transmission Operator did not inform three other known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is less, of its actual or	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR

			resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform one other known impacted Balancing Authorities or 5% or less of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions	operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform two other known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas	expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three other known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on	The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform four or more other known impacted Balancing Authorities or more 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could

			did permit such communications.	when conditions did permit such communications.	respective Balancing Authority Areas when conditions did permit such communications.	have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.

Proposed TOP-001-3, Requirement R13:

R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	The Transmission Operator did not perform Real-time Assessments. For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.

Proposed TOP-002-4, Requirement R1, Severe VSL: The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).

Proposed TOP-002-4, Requirement R4, Severe VSL: The Balancing Authority did not have an Operating Plan.

Proposed TOP-003-3, Requirement R3, Severe VSL: The Transmission Operator did not distribute its data specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed TOP-003-3, Requirement R5:

R5	Operations Planning, Same-Day Operations Real-time Operations	Medium	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3). OR, The responsible

						entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

Organization	Yes or No	Question 14 Comment
Northeast Power Coordinating Council	No	IRO-008-2: R5 requires a real-time assessment every 30 minutes. The VSL is graduated in 5 minute increments. The VSL does not specify the period being measured. The existing IRO-008-1 utilizes a 24 hour sampling in the existing VSL. A similar approach should be used. Each VSL should be checking the completed assessments in a 24 hour period and that the periodicity was within a time bound. So VSL Low would be: The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes OR for any sample 24 hour period within the 30 day retention period, a Real-time Assessment was not conducted for one 30-minute period within that 24-hour period. IRO-014--In the VSL Table repeat the header row for all pages containing the VSL table. IRO-014 R6 (Severe VSL) : in order to be consistent with other standards, change the tense of the verb "exists" to "existed". IRO-017-- R2 VRFs should be Medium, not Low. This is a performance requirement.

Organization	Yes or No	Question 14 Comment
		TOP-001 R3 thru R6 VSLs--an Operating Instruction applies to both Normal and Emergency operations. Therefore the VSL should be graduated similarly to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is Moderate VSL. In the VSL Table, for R3 and R5 (Severe VSL), suggest changing the sentence to "The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator when such an action could have been physically implemented and would not have violated safety, equipment, regulatory or statutory requirements." In the VSL Table for R7 (Severe VSL), suggest changing the sentence to "The Transmission Operator or Balancing Authority did not provide assistance to Transmission Operators, if requested, when the requesting entity had implemented its emergency procedures when such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements." In the VSL Table for R8 (all VSL levels) change the tense of the verb "result in" to "resulted in, or could have resulted in ...." to match the rest of the VSL that is written in the same tense. (Extracted from Q1) IRO-001-4: An Operating Instruction applies to both Normal and Emergency operations. Therefore, the VSL should be graduated similar to COM-002-4 R5. OI issued during an Emergency is a Severe VSL and OI issued during Normal events is a Moderate VSL. (Extracted from Q4) IRO-010-2: Similar to TOP-003, R1 and R2 VRFs should be Low, not Medium. (Extracted from Q7) TOP-001-3: Requirement R5 has a zero-defect problem similar to what was argued for COM-002-4. A single instance of a failure to comply with any Operating Instruction results in a severe violation. We recommend a revision to this approach more consistent with the COM-002-4 penalties. A demonstrated pattern of

Organization	Yes or No	Question 14 Comment
		problems would trigger a Severe VSL, but isolated single events, which did not impact the BES, should not be penalized. (It is hard to argue that not following an OI when one can during an Emergency would not be a severe VSL. Graduated levels could be similar to COM-002-4 R5.) FERC has stated that VSLs should be graded. These are not. Further, intent to perform should count in favor of any entity that is unable to implement an Operating Instruction due to a technical or reliability related concerns. (It is hard to argue that not following an OI when one can during an Emergency would not be Severe. Graduated levels could be similar to COM-002-4 R5.)

Response: Proposed IRO-008-2, Requirement R5: The SDT agrees and has adjusted the data retention period and VSLs to correspond with those in approved IRO-008-1. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision.

Proposed IRO-014-3: The SDT agrees and has made the required change to incorporate the header on each page of the VSL Table.

Proposed IRO-014-3, Requirement R6: The SDT agrees and has made the suggested change. See summary consideration for revision.

Proposed IRO-017-1, Requirement R2: The SDT agrees and has made the suggested change. See summary consideration for revision.

Proposed TOP-001-3, Requirements R3 through R6: The SDT agrees that Operating Instructions can be issued during both normal and Emergency conditions. However, the requirements intentionally do not differentiate between such conditions. One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. The SW Outage report showed the importance of following Operating Instructions regardless of the situation. No change made.

Proposed TOP-001-3, Requirements R3 and R5: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Proposed TOP-001-3, Requirement R7: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Proposed TOP-001-3, Requirement R8: The SDT agrees and has made the suggested changes. See summary consideration for revision.

Proposed IRO-001-4: The SDT does not believe that the suggested change provides any additional clarification. No change made.

Organization	Yes or No	Question 14 Comment
Proposed IRO-010-2, Requirements R1 and R2: The SDT agrees and has made the suggested changes. See summary consideration for revision. Proposed TOP-001-3, Requirement R5: The SDT agrees that Operating Instructions can be issued during both normal and Emergency conditions. However, the requirements intentionally do not differentiate between such conditions. One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. An entity has the opportunity to inform the Balancing Authority of its inability to perform as shown in Requirement R6. No change made.		
SERC OC Review Group Associated Electric Cooperative, Inc. - JRO00088	No	IRO-001-13, R1.3, IRO-008-2 R5. The SERC OC Review Group has concerns that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Low 30 minutes, high VSL 45 minutes) Suggestion: expand bandwidth. (Extracted from Q7) TOP-001-3: In the R13 VSLs, there is concern that the bandwidth between "lower" and "severe" VSL is only 15 minutes. Suggestion: expand bandwidth. See also response on IRO-008-2, question 3 above.

Organization	Yes or No	Question 14 Comment
Response: IRO-001-13, Requirement R1.3: There is no such standard or requirement. The SDT believes this is a typo and has been answered with the response to proposed IRO-008-2. Proposed IRO-008-2, Requirement R5: The SDT has made changes to the VSLs based on other comments that should address your concerns. In addition, the SDT has changed the Time Horizon to correspond to proposed TOP-001-3, Requirement R13. See summary consideration for revision.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Idaho Power	No	
Response: Without specific comments, the SDT is unable to respond.		
MidAmerican Energy	No	The VRFs and VSLs will need to be adjusted. (Extracted from Q3) IRO-008-2: Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: Proposed IRO-008-2, Requirement R5: The SDT has made changes to the VSLs based on other comments that should address your concerns. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision.		

Organization	Yes or No	Question 14 Comment
Duke Energy	No	1. As previously stated in TOP-001 R3, the definition of Operating Instruction makes this requirement (and standard as a whole), too broad in nature. The definition of Operating Instruction carries past the parameters of action in an Emergency situation, and includes all actions. To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written. 2. (Extracted from Q1) IRO-001-4: To apply a High VRF level, accompanied with a Severe VSL, is in our opinion, an inappropriate classification for the standard as written.
Response: Proposed TOP-001-3, Requirement R3: One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. No change made. Proposed IRO-001-4: No requirement is provided but the SDT believes this comment is addressing the same issue as proposed TOP-001-3, Requirement R3 above and believes that the same response is appropriate. No change made.		
SPP Standards Review Group INDN - Independence Power & Light	No	TOP-001-3 Delete the phrase '...in Severe VSL for Requirement R3 citing one of the specific reasons shown in Requirement R3.' This will make this VSL parallel the Severe VSL of Requirement R6. Either that or add the phrase to the Severe VSL in Requirement R6. Change all the VSLs such that they read: '...that result in, or could result in, an Emergency in those respective Transmission Operator Areas...' The proposed VSLs for Requirement R13 address not completing the Real-time Assessments within a specified time frame. This makes no adhering to the 30-minute criteria a zero-tolerance requirement. Why not use criteria that are more flexible and reflect a measure of up-time for the assessments? For example, Real-time Assessments were completed within more than 98% but less than 100% of the 30-minute windows during a calendar year. The way the VSL is written if one assessment

Organization	Yes or No	Question 14 Comment
		is not completed within 30 minutes, the entity is just as guilty as if none of the assessments are completed. TOP-002-4Change 'will exceed' in the Severe VSL for Requirement R1 to 'exceeded'. Change 'does' in the Severe VSL for Requirement R4 to 'did'. TOP-003-3Capitalize 'Real-time' in the Severe VSL for Requirement R3. We suggest adding the phrase 'as specified in Requirement R5' at the end of the Severe VSL for Requirement R5. IRO-001-4Use a lower case 'issued' in the Severe VSL for Requirement R3. IRO-008-2Replace 'have an' with 'perform' in the Severe VSL for Requirement R1. The requirement calls for the Reliability Coordinator to perform an Operational Planning Assessment, not to have an assessment. Add the phrase 'in Requirement R2' at the end of the Severe VSL for Requirement R3. Rather than tie compliance to the timing of a single Real-time Assessment in the VSLs for Requirement R5 making this a zero-tolerance requirement, we recommend that the SDT use a performance based, on-time criterion. For example, the Lower VSL could be The Reliability Coordinator performed a Real-time Assessment at less than 100% of the time but more than 98% of the time. The Moderate, High and Severe VSLs would be adjusted in a similar manner. We recommend the Moderate, High and Severe VSLs for Requirement R6 begin with 'The Reliability Coordinator did not notify a total of X impacted Transmission Operators or Balancing Authorities...' A similar change needs to be made for the Moderate, High and Severe VSLs for Requirement R8 except that the 'or' is already used there. Replace 'are' with 'were' in the Severe VSL for Requirement R7. Replace the 'has been' with 'was' in all the VSLs for Requirement R8.

Organization	Yes or No	Question 14 Comment
		IRO-010-2Capitalize Part in the Lower, Moderate and High VSLs for Requirement R3. IRO-014-3Replace 'failed to' with 'does not' in the Severe VSL for Requirement R1. Add the phrase 'specified in Requirement R2' at the end of the Lower, Moderate and High VSLs for Requirement R2. Insert 'has the' between 'Coordinator' and 'Operating Procedures' in the Moderate VSL for Requirement R2. Insert 'the' between 'has' and 'Operating Procedures' in the Moderate VSL for Requirement R2. Insert 'all' between 'meet' and 'three' in the Moderate VSL for Requirement R2. Replace 'does' with 'did' in the Severe VSL for Requirement R2. Aren't the Severe VSLs for Requirements R1 and R2 identical and therefore creating a double jeopardy situation? Insert 'as specified in Requirement R3' between 'Coordinators' and 'in' in all the VSLs for Requirement R3. Replace 'the problem' with 'an Emergency' in the Severe VSL for Requirement R6. Replace the Severe VSL for Requirement R9 with the following: 'The Reliability Coordinator did not provide assistance to a requesting Reliability Coordinator that had implemented its emergency procedures and such actions could have been physically implemented or would not have violated safety, equipment, regulatory, or statutory requirements.'

Organization	Yes or No	Question 14 Comment
Response: Proposed TOP-001-3, Requirement R3: The indicated phrase does not appear in the VSL. Proposed TOP-001-3: No requirement was provided but the SDT believes the comment is with respect to Requirement R8. The SDT agrees and has made the suggested change. See summary consideration for revision. Proposed TOP-001-3, Requirement R13: The SDT has changed the data retention and VSLs for this requirement in order to correspond with those for approved IRO-008-1 and believes that this will address your concerns. See summary consideration for revision. Proposed TOP-002-4, Requirement R1: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-002-4, Requirement R4: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-003-3, Requirement R3: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed TOP-003-3, Requirement R5: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-001-4, Requirement R3: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R1: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R3: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-008-2, Requirement R5: The SDT has changed the data retention and VSLs for this requirement in order to correspond with those for approved IRO-008-1 and believes that this will address your concerns. In addition, the SDT has changed the Time Horizon to correspond with that of proposed TOP-001-3, Requirement R13. See summary consideration for revision. Proposed IRO-008-2, Requirement R6: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-008-2, Requirement R8: The SDT does not believe that the suggested change adds any clarity. No change made.		

Organization	Yes or No	Question 14 Comment
Proposed IRO-008-2, Requirement R7: The SDT agrees and has changed the Severe VSL accordingly. See summary consideration for revision. Proposed IRO-008-2, Requirement R8: The SDT agrees and has made the suggested changes. See summary consideration for revision. Proposed IRO-010-2, Requirement R3: The SDT agrees and has changed the VSLs accordingly. See summary consideration for revision. Proposed IRO-014-3, Requirement R1: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R2: The SDT agrees and has changed the VSLs accordingly. These changes should eliminate your concerns about possible double jeopardy. See summary consideration for revision. Proposed IRO-014-3, Requirement R3: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R6: The SDT does not believe that the suggested change adds any clarity. No change made. Proposed IRO-014-3, Requirement R9: The SDT does not believe that the suggested change adds any clarity. No change made.		
ACES Standards Collaborators	No	(1) As mentioned in earlier comments, there are several instances in the standards where binary treatment is made to the VSL table where graduated violations could be implemented. (2) In regard to VRFs, we question the need for any requirement that has a low risk factor. We ask the SDT to review the Low VRF requirements to determine if these tasks truly impact reliability. (3) (Extracted from Q1) IRO-001-4: We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.

Organization	Yes or No	Question 14 Comment
		(4) (Extracted from Q2) IRO-002-4: We question the binary nature of the VSL tables and ask the SDT to consider graduated treatment of violations.
Response: (1) The SDT has responded to all specific requests regarding binary treatment of VSLs. (2) The SDT reviewed all of the VRF assignments. Those requirements assigned a Lower VRF have been deemed as necessary for reliability and not simply administrative tasks. (3) Proposed IRO-001-4: One either complies with the Operating Instruction or one doesn't. Furthermore, the requirements are set up on an individual Operating Instruction basis which leads to an all or nothing evaluation of compliance and thus the binary severe VSL. No change made. (4) Proposed IRO-002-4: The SDT has adjusted the VSLs for Requirements R1 and R2 to gradate the terms to correspond to approved IRO-002-2. See summary consideration for revision.		
ISO/RTO Standards Review Committee (SRC) Independent Electricity System Operator	No	Please reference above comments regarding individual draft standards. In addition, we offer the following comments: a. IRO-008-2, R6: The LOWER VSL which makes reference to "Emergency" should be changed to "anticipated or actual SOL/IROL exceedance". Please see our comment under Q3, above, for details. b. IRO-010-2, R1: The SEVERE VSL for R1 can be reworded to "The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." Since there are only 4 parts in R1 and hence the "four or more" is inappropriate. c. IRO-017-1, R1: We do not believe the VSL for R1 should not be binary. R1 requires the RC to identify the roles and develop a process for coordinating outage plans, the latter to include several elements. It may well be a case where the RC did develop the process but missed some of the elements listed in Parts 1.1 to 1.4. For example, a LOWER VSL may be assigned if the RC did develop identify the roles and develop the process document, but missed one of the parts in 1.1 to 1.4. A MEDIUM VSL may be

Organization	Yes or No	Question 14 Comment
		assigned if the RC missed two of the parts, etc. We suggest the SDT to review the VSL development guideline and FERC's guideline, and revise the VSL for R1 accordingly. d. TOP-001-3, several requirements: Since we disagree with a number of requirements in this standard, we are unable to support the VSLs associated with these requirements. e. TOP-003-3, R5: This requirement contains 3 parts each of which specifies a particular aspect of data provision. It is conceivable that a responsible entity provided data as specified in R3 and R4 but failed to follow one or more of the specific format, process or protocol as depicted in Parts 5.1 to 5.3. Hence, having a binary VSL for R5 would imply that failing to meet just one of Parts 5.1 to 53 will render the responsible entity being assessed a SEVERE violation. This is inconsistent with the VSL guideline. We suggest the SDT to expand the VSL for R5 to cover the cases of failing to meet one and two of the three parts in R5. (Extracted from Q6) IRO-017-1: R2 VRFs should be Medium, not Low. (note: CAISO does not agree with this comment).
Response: a. Proposed IRO-008-2, Requirement R6: The term 'Emergency' is not included in the Lower VSL. No change made. a. Proposed IRO-010-2, Requirement R1: The SDT agrees and has made the suggested change. See summary consideration for revision. b. Proposed IRO-017-1, Requirement R1: The SDT agrees and has made the suggested change. See summary consideration for revision. c. Proposed TOP-001-3: Without specific comments on the VSLs, the SDT is unable to respond. d. Proposed TOP-003-3, Requirement R5: The SDT agrees and has made the suggested changes. See summary consideration for revision. e. Proposed IRO-017-1, Requirement R2: The SDT agrees and has made the suggested change. See summary consideration for revision.		
Georgia System Operations	No	The bandwidth between "lower" and "severe" VSL is only 15 minutes. Expand bandwidth.

Organization	Yes or No	Question 14 Comment
Georgia Transmission Corporation		
Response: The SDT assumes this is referring to proposed TOP-001-3, Requirement R13 and/or proposed IRO-008-2, Requirement R5. The SDT has changed both sets of VSLs based on previous comments. See summary consideration for revision.		
Rutherford EMC	No	See comments on TOP-003. (Extracted from Q9) TOP-003-3: In the Table of Compliance Elements, the severity and risk for R5 is medium with only a Severe VSL. All other requirements in this standard are low and have graduated levels of severity. In IRO-10, the same failure has graduated levels of severity. This is inconsistent and should be rectified.
Response: The SDT agrees and has made the items consistent as suggested. See summary consideration for revision.		
Austin Energy	No	City of Austin dba Austin Energy (AE) provides the following comments regarding VSLs: (1) The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. (2) The VSL for IRO-010-2, R2 should have the note regarding starting at the Severe VSL similar to TOP-003-3, R3 and R4 and others. (3) The VSLs for TOP-001-3, R3 and R5 should parallel the VSL for IRO-001-4, R2. (4) The VSLs for TOP-001-3, R4 and R6 should parallel the VSL for IRO-001-4, R3.
Response: (1) The SDT agrees and has made the suggested changes. See summary consideration for revision. (2) The SDT agrees and has added the note as suggested. See summary consideration for revision. (3) While the language is not identical, the content and intent of the proposed TOP-001-3, Requirements R3 and R5 VSL do parallel the content and intent of proposed IRO-001-4, Requirement R2 VSL. No change made. (4) While the language is not identical, the content and intent of the VSLs for proposed TOP-001-3, Requirements R4 and R6 do parallel the VSL for proposed IRO-001-4, Requirement R3. No change made.		

Organization	Yes or No	Question 14 Comment
Electric Reliability Council of Texas, Inc.	No	Please reference above comments regarding individual draft standards.
Response: Please see responses to previous comments.		
Sacramento Municipal Utility District/Balancing Authority Northern California	No	No, the IRO-002-4 VSL provide no alternative other than Severe. In cases where one element of several hundreds could be missed this effectively creates a zero tolerance.
Response: No requirements are specified here so the SDT is unable to provide a detailed response. However, the SDT did change the VSLs for both Requirements R1 and R2 of proposed IRO-002-4 based on other comments and believes this may address the commenter's concerns. See summary consideration for revision.		
PJM Interconnection	Yes	(Extracted from Q12) IRO-008-2, R5: Additionally, the VRF and VSLs for R5 will require revision to address the two hour timeframe allowed for in EOP-008.
Response: The SDT has made changes to IRO-008-2, Requirement R5 data retention and VSLs based on comments received that should address your concerns. See summary consideration for revision.		
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
PPL NERC Registered Affiliates	Yes	
Peak Reliability	Yes	

Organization	Yes or No	Question 14 Comment
Rayburn Country Electric Cooperative	Yes	
EDP Renewables North America LLC	Yes	
Volkmann Consulting	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	
PNMR	Yes	
Consumers Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Salt River Project	Yes	
Response: Thank you for your response.		

15. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

Summary Consideration: The SDT has provided clarification to numerous comments and has made the following changes due to industry comments:

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Effective Date/Implementation Plan for proposed IRO-010-2 and TOP-003-3: Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Organization	Yes or No	Question 15 Comment
PacifiCorp	Yes	Although PacifiCorp supports the elimination of duplicate language in these Standards, much of the new language in the revised Standards is diluted and is more vague as a result.
Response: Without specific comments, the SDT is unable to respond.		

Organization	Yes or No	Question 15 Comment
FRCC Operating Committee (Member Services) Seminole Electric Cooperative, Inc	Yes	1. Special Protection Systems should be addressed in their own requirements. 2. Phase Angle limitations should be greater than 300 kV. 3. The FRCC MS OC would like to thank the TOP/IRO SDT for their time and effort in developing the proposed changes to the NERC Reliability Standards as part of this important initiative. We support the SDT efforts conceptually, and have provided comments on improving the language and clarity of some of the proposed requirements. However we do have some questions and concerns that need to be addressed prior to giving the project our full support.
Response: 1. These standards only deal with data from Special Protection Systems or to make certain that the data is included in analysis and assessments. Technical details concerning Special Protection Systems remain in the PRC standards. No change made. 2. With no technical justification provided for the suggested change, the SDT is unable to provide a response. No change made. 3. Thank you for your support.		
Duke Energy	Yes	As stated in our comments above, Duke Energy has significant concerns regarding aspects of the proposed TOP/IRO standards. We believe they are in direct conflict with the current Functional Model roles and responsibilities upon which the industry has built processes, procedures, software, and infrastructure. The industry approved Functional Model defines the various relationship, functions, the tasks performed by these functions, the responsible time horizons and the relationships between the entities responsible for performing tasks associated with each function. It is this model that provides the foundation and the framework upon which NERC is to develop and maintain Reliability Standards. Furthermore, the idea that reliability begins with and centers completely around the RC is a mistake as it removes the defense-in-depth strategy currently in place. The RC should be the last line of defense, not the first. Reliability does not start with the RC; it begins with the TOPs and BAs and the standards should acknowledge and emphasize this important tenet of reliability. The RC's role is to maintain a wide-area

Organization	Yes or No	Question 15 Comment
		view and prevent system events - having them involved in every TOP's normal operations at all times distracts from the RC's responsibility and will have significant consequences. Duke Energy is not opposed to visiting the re-assignment of said responsibilities and applicable time horizons, however, we feel that this task should be done through an amendment of the Functional Model, and not through the Reliability Standards process.
Response: The SDT believes the proposed standards are consistent with the NERC Functional Model and responsive to concerns raised by FERC in the NOPR. Specific responses to Duke's comments on the functional model are provided in the appropriate sections.		
FirstEnergy	Yes	FirstEnergy recommends striking the words "or degradation" in the proposed definitions for both Operating Planning Analysis and Real Time Assessments.
Response: The SDT believes that degradation information is necessary for an appropriate level of situational awareness. No change made.		
SPP Standards Review Group	Yes	There are numerous instances in the Measures of all the proposed standards where the phrase 'but not limited to' is included. In some instances this phrase is set off by commas and in others it is not. When the commas are used, the second comma appears out of place. We suggest deleting the commas entirely as it is done in several of the Measures. Requirements R10 and R11 in TOP-001-3, Requirement 1, Part 1.2 in TOP-003-3, Requirement R4 in IRO-002-4, Requirement R1, Part 1.2 and the revised definitions for Operational Planning Analysis and Real-time Assessment include a reference to the term Special Protection Systems. There is a new proposal at NERC to replace this term with Remedial Action Scheme. If this change comes about, how will this change be reflected in this set of revised standards?
Response: The SDT agrees and has removed all commas.		

Organization	Yes or No	Question 15 Comment
The SDT must use the terms as they presently exist in the approved Glossary of Terms. Another team is working on the Special Protection System/Remedial Action Scheme issue. If they decide to make that change, part of their responsibility will be to bring all standards up to date with this change.		
ACES Standards Collaborators Georgia Transmission Corporation	Yes	(1) We recommend that the drafting team post redlines with each standard, so it is easier to view the proposed changes. Having clean copies of the revisions only adds more time to have to track changes and it is a very inefficient use of industry's time. (2) The drafting team should consider reducing the amount of information in the posting, or extending the comment period to allow for a thorough review by industry. We recommend holding a technical conference or a series of webinars (instead of just one) to go through each of the standards in detail. The amount of information cannot be covered in a single hour-long webinar. (3) Why did the SDT not review PRC-001? The words "coordinate" and "familiar" are ambiguous words that have caused issues with compliance and enforcement for years. It is disappointing that this issue has not been addressed. (4) Thank you for the opportunity to comment.
Response: (1) It is not practical to review redlined versions of the standards for this project due to the extensive revisions from the currently enforceable standards. The mapping document is a more efficient mechanism for tracking changes. (2) The SDT will provide additional opportunities to discuss details of the proposed standards with stakeholders in the future. Because the standards must be filed with FERC by January 15, it is not possible to provide longer comment periods. The tremendous effort put forth by the industry to review the standards and provide thoughtful feedback has kept the project on track and is deeply appreciated by the SDT. (3) PRC-001 is not in scope for this project.		
Peak Reliability	Yes	Operational Planning Analysis proposed definition should address the modeling of impacts of sub-100 kV and SPS/RAS - not just the status of SPS/RAS.

Organization	Yes or No	Question 15 Comment
		Also “The evaluation shall reflect inputs” should be “The evaluation reflects inputs” to avoid the appearance of having a Requirement within a definition.
Response: As written in the proposed definition, an Operational Planning Analysis is an evaluation of projected system conditions to assess anticipated and potential conditions for next day operations. Certain inputs, like Protection System and Special Protection System status, are specified to ensure that the Operational Planning Analysis contains sufficient detail to provide appropriate situational awareness. The proposed definition describes what an Operational Planning Analysis is, and the SDT believes that a description of how an Operational Planning Analysis is conducted as suggested by the commenter is not necessary. To address this and other feedback from industry, the SDT has added “applicable” to the definition of Real-time Assessment and Operational Planning Analysis to further clarify the definitions. See summary consideration for revision.		
CenterPoint Energy Houston Electric LLC.	Yes	CenterPoint Energy is concerned with the existing NERC defined term Transmission Operator Area being introduced in the TOP Standards as it is currently written. Transmission Operator Area: The collection of Transmission assets over which the Transmission Operator is responsible for operating. In the ERCOT region individual Local Control Centers operate Transmission assets under the direction of ERCOT ISO while both are jointly registered Transmission Operators under a Coordinated Functional Registration. CenterPoint Energy recommends a revised definition under Section D, Regional Variances to address this established joint responsibility. The revised definition would read as follows: Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation.
Response: The SDT believes that a variance is not required as it is widely understood that acting could include directing others to act. And the responsibility for actions doesn’t change regardless of whether the Transmission Operator performs the actual actions itself or directs others to do the actions. No change made.		
City of Garland	Yes	Implementation Plan Concern In the Implementation Plan, IRO-010-2 and TOP-003-3 both have requirements that are intended to go into effect on different dates to allow data specifications to be developed / distributed to entities and those receiving entities have time to gather / format data and send back to the requesting entities.

Organization	Yes or No	Question 15 Comment
		Both effective dates refer to the 1st day of the 1st calendar quarter that occurs either 10 months or 12 months after the approval date (FERC's approval in the US). Because of the 2 months separation, there is one month in each quarter that if FERC approves the standards in that month, the 10 months & 12 months later will both fall in the same quarter resulting both effective dates starting on the same 1st day of the 1st quarter following. Recommendation: Change language to where the two sets of requirements will go into effect one quarter apart. Definitions Concern is with the portion of the definition of "Operational Planning Analysis" and "Real Time Assessments" that lists "identified phase angle". It is not clear what "identified" means. "Identified" should mean that the Entity will identify representative points across the area for which it is responsible - not every available point in the system (larger geographic areas would probably need more points than small geographic areas). Also, PMUs require a large bandwidth to pass the tremendous amount of data collected thus making the communication costs prohibitive for small entities.
Response: The SDT agrees and has changed the Implementation Plan to a 9 month/12 month increment as well as the Effective Dates for proposed IRO-010-2 and TOP-003-3. See summary consideration for revisions. The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. The SDT has added the term 'applicable' to the definition list for clarification. No change made. If an entity does not have PMU data then this is not an issue. If an entity has PMU data, then the SDT believes that the entity will have built its systems to be able to handle the volume of data associated with the PMU data. The Reliability Coordinator is not going to request data just for the sake of having it and will only request data that it truly needs. This could assist in dealing with the volume of data going across the link. In addition, the requirement cites mutual agreeability which assures that the controlling entity can't request something that the submitting entity simply can't provide. No changes made.		
American Electric Power	Yes	AEP's negative vote on TOP-002-4 is solely driven by the proposed definition on which it relies, not on the direction or intent of the standard itself. Comments

Organization	Yes or No	Question 15 Comment
		regarding proposed definitions: Operating Planning Analysis: ”Identified phase angle...limitations” needs to be clarified. The definition could be interpreted as requiring either a) continual analysis of all phase angles or b) analysis of pre-determined phase angle limitations at specific locations. AEP believes the definition should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. In the event continual analysis is required, what determines the placement and number of measurements for a given system? In that case, the definition should clarify that if phase angle is considered in the study, and if a phase angle limitation is identified, than that limitation should be included in the analysis. Rather, AEP proposes the following definition: “An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation should reflect inputs such as (but not limited to): load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.)” Real-time Assessment: Once again, AEP has concerns similar those expressed for the definition of Operating Planning Analysis, as the definition for Real-time Assessment should specifically state that it applies only to analysis of pre-determined phase angle limitations at specific locations. We propose the following definition: “An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment should reflect inputs such as (but not limited to): load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)”

Organization	Yes or No	Question 15 Comment
Response: The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. The SDT has added the term 'applicable' to the definition list for clarification. No change made.		
NIPSCO	Yes	NIPSCO has the following comments about the new Definitions: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. 2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?
Response: The SDT believes it is appropriate to consider Facility Rating and equipment limitations in the Operational Planning Analysis and Real-time Assessment and not limit the inputs to more narrowly defined SOLs and IROLs. No change made. Identified phase angle and equipment limitations are listed as an input in response to Southwest Outage Report recommendation number 27. The proposed definition works in concert with requirements in the proposed standards (e.g., proposed TOP-001-3 Requirement R14) to provide the necessary situational awareness for reliable operations. The proposed definition provides flexibility for the responsible Transmission Operator, Balancing Authority, or Reliability Coordinator to determine specific inputs. Those entities will only be asking for such data where they feel they need it and the data specification concept will allow entities to come to mutual agreement as to what phase angle data is required.		
PJM Interconnection	Yes	PJM recommends that the drafting team review the requirements in the TOP standards which are applicable to the BA and in which the GO is performing a specific requirement. PJM suggests these requirements be reviewed and moved to the appropriate BAL standards, if they are determined to still be necessary.
Response: The SDT generally supports the concept of having the TOP standards for the Transmission Operator, the IRO standards for the Reliability Coordinator and the BAL standards for the Balancing Authority; however, BAL standards are not in the scope of this		

Organization	Yes or No	Question 15 Comment
project. Therefore, the SDT believes the requirements and applicable entities are currently organized appropriately to support the purpose of each proposed standard and in response to the defined scope of this project. No change made.		
Austin Energy	Yes	City of Austin dba Austin Energy (AE) provides the following comments on the definitions of Operational Planning Analysis and Real-time Assessment: (1) Consider changing the use of the term "Special Protection System" to "Remedial Action Scheme" to match Project 2010-05.2. (2) Please clarify what is meant by incorporating "identified phase angle and equipment limitations." Does the SDT intend this to cover limitations in real and reactive capability? (3) Additionally, AE provides this third comment on the definition of Transmission Operator Area, which is rarely used in existing standards but is included in the TOP/IRO family revisions. In the ERCOT Region, both ERCOT ISO and each local control center are each registered as TOPs. A CFR matrix delineates the responsibility for each requirement applicable to the TOP function. The general concept in the ERCOT Region is that individual local control centers operate Transmission assets under the direction of ERCOT ISO. Logically, one would assume that each Transmission Operator would have a Transmission Operator Area. However, the current definition poses a potential conflict. As defined in the NERC Glossary, a Transmission Operator Area is "The collection of Transmission assets over which the Transmission Operator is responsible for operating." ERCOT does not operate Transmission assets, rather, it directs the operation of Transmission assets. Therefore, AE suggests a revision and regional variance to the definition as follows: "Transmission Operator Area (ERCOT Region): The collection of Transmission assets over which the Transmission Operator is responsible for operating or directing operation."
Response: The SDT must use the terms as they presently exist in the approved Glossary of Terms. Project 2010-05.2 is working on the Special Protection System/Remedial Action Scheme issue. If they decide to make that change, part of their responsibility will be to bring all standards up to date with this change.		

Organization	Yes or No	Question 15 Comment
The part of the definition that is referenced here is actually **"…** *and identified phase angle and equipment limitations…"* This means that any identified limitations in dealing with phase angles should be incorporated into the analysis. No constraints exist as to Real or Reactive Power. The SDT has added the term 'applicable' to the definition list for clarification. No change made. The SDT believes that a variance is not required as it is widely understood that acting could include directing others to act. And the responsibility for actions doesn't change regardless of whether the Transmission Operator performs the actual actions itself or directs others to do the actions. No change made.		
Oncor Electric Delivery LLC	Yes	Oncor does not support the two proposed definitions in proposed in Project 2014-03 Revisions to TOP/IRO Reliability Standards; Operational Planning Analysis and Real-time Assessment. The definitions state the minimum inputs that must be included in the evaluation of each Operational Planning Analysis and Real-time Assessment for pre and post contingency conditions. Some of the inputs listed that shall be included are not feasible for post contingency analysis, such as phase angles. For Oncor to approve the definitions, recommend changing the wording from "shall reflect inputs including" to "may reflect inputs including" in both definitions. Operational Planning Analysis Oncor's proposed recommendation: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted services.) Real-time Assessment Proposed definition: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted services.)"

Organization	Yes or No	Question 15 Comment
		Furthermore, Oncor has concern that the proposed Standards place unnecessary requirements on Transmission Operators (TOPs) to run Operational Planning Analysis and Real-time Assessments. As stated in response to Question 7 (TOP-001-3) and Question 12, the ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPs and has a centralized view of the entire region to maintain reliability. Requiring Transmission Operators to replicate Real-time Assessments and Operational Planning Analysis currently performed by the Reliability Coordinator (ERCOT) creates added expense and contributes no added reliability to the BES. Oncor requests the SDT consider placing these functions (Operational Planning Analysis and Real-time Assessment) on the Reliability Coordinators only.
Response: To address this and other feedback from industry, the SDT has added "applicable" to the definition of Real-time Assessment and Operational Planning Analysis to further clarify the definitions. See summary consideration for revision.		
Texas Reliability Entity	Yes	1) Operational Planning Analysis definition: Recommend returning the phrase "may be performed either a day ahead or as much as 12 months ahead" to the proposed definition of Operational Planning Analysis. That language includes the full Operations Planning horizon, not just next day. The current effective definition contains that phrase. Development of an Operating Plan to address the exceedances of SOLs/IROLs may take longer than one day to develop, so it is necessary to have a requirement to perform an Operational Planning Analysis for the full Operations planning horizon. The proposed definition, in conjunction with TOP-002-4 R1 which directs TOPs to have an Operational Planning Analysis for the next day to assess whether there will be a SOL exceedance, doesn't account for the time frame from after one day up to 12 months. 2) There is a discrepancy between the definition of "operations planning horizon" in the Project 2014-03 SOL Exceedance White Paper and IRO-017-1. The white paper defines operations planning time horizon as "operating and resource plans from day-

Organization	Yes or No	Question 15 Comment
		ahead up to and including seasonal." IRO-017-1 (Note on part 1.5) defines the operations planning horizon as "next-day to one year out."
Response: 1) The SDT believes the suggested phrase is unnecessary. Neither the proposed definition nor the requirements specifically state when the Operational Planning Analysis is created, so an entity could prepare it at any time provided it reflects accurate inputs for next-day operations. 2) The correct usage is next-day to one year out. The SOL Exceedance White Paper has been updated to reflect this change.		
Salt River Project	Yes	TOP-003-3 R5 does not adequately cover the planning aspects of TOP-002-2.1b R15. TOP-003-3R5 seems to be a “follow direction” requirement where TOP-002-2.1b is a planning requirement.
Response: The proposed requirements in proposed TOP-003-3 work collectively to provide for the data needs of the Transmission Operator and Balancing Authority to fulfill their operational and planning responsibilities. The data specification allows for the Transmission Operator/Balancing Authority to ask for any data they need which could include the forecast of real power output previously cited in approved TOP-002-2.1b Requirement R15. No change made.		
Rayburn Country Electric Cooperative	No	: I would reinforce my support for reduction of standards by consolidation of requirements that use nearly identical if not identical language by creating role based groups of functional entities. I believe it makes a requirement clearer to understand since it is found only once within the NERC standards not in 2 or 3 different standards. It makes training easier as well, allowing the focus to be on the required action.
Response: The SDT purposely kept these standards separate to keep the focus on the functional entities responsible: Reliability Coordinators for proposed IRO standards and Transmission Operators and Balancing Authorities for proposed TOP standards. This was part of the scope for the originating projects (Project 2006-06 and Project 2007-03). No change made.		
Northeast Power Coordinating Council	No	

Organization	Yes or No	Question 15 Comment
Arizona Public Service Company	No	
Associated Electric Cooperative, Inc. - JRO00088	No	
Colorado Springs Utilities	No	
SERC OC Review Group	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
PPL NERC Registered Affiliates	No	
ISO/RTO Standards Review Committee (SRC)	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 15 Comment
Georgia System Operations	No	
EDP Renewables North America LLC	No	
Volkmann Consulting	No	
Manitoba Hydro	No	
Exelon Ccompanies	No	
Ingleside Cogeneration LP	No	
Xcel Energy	No	
American Transmission Company	No	
Idaho Power	No	
PNMR	No	
David Kiguel	No	
Consumers Energy	No	
Liberty Electric Power, LLC	No	
Hydro One	No	

Organization	Yes or No	Question 15 Comment
Tri-State Generation and Transmission Association, Inc.	No	
Hydro One	No	I sent in comments earlier but I have updated them now to include comments about IRO-017-1.
INDN - Independence Power & Light	No	
MidAmerican Energy	No	
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that significant progress has been made to address the FERC orders, expert recommendations, and remove redundancies while maintaining reliability-based requirements. Outside of the issues raised in our comments and the IRC SRC comment, ERCOT supports the remainder of the proposed changes.
Response: Thank you for your response.		

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - **4.5.** Load-Serving Entity
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to ensure the reliability of its Transmission Operator Area.

R2. Each Balancing Authority shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to ensure the reliability of its Balancing Authority Area.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each

Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. 'Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures. These changes are in response to IERP recommendations.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that requested assistance, if able, was provided to other Transmission Operators unless

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

such assistance cannot be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities.

R10. Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities, the status of Special protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL)

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

for a continuous duration exceeding its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the system to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator and Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R2. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area (Balancing Authority Area). *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area (Balancing Authority Area). *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, and R14 through R20 and Measure M1 through M11, and M14 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act, or direct others within its Transmission Operator Area to act, to ensure the reliability of its Transmission Operator Area.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act, or direct others within its Balancing Authority Area to act, to ensure the reliability of its Balancing Authority Area.
R3	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an Operating

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-Time Operations					Instruction issued by its Transmission Operator.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide assistance to other Transmission Operators, if requested and able, when the requesting entity had implemented its emergency procedures, and such actions could have been physically implemented and would not have violated safety,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						equipment, regulatory, or statutory requirements.
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR,	The Transmission Operator did not inform two other known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not	The Transmission Operator did not inform three other known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three other known impacted Balancing	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Transmission Operator did not inform one other known impacted Balancing Authorities or 5% or less of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	inform two other known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	Authorities or more than 10% and less than or equal to 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	conditions did permit such communications. OR, The Transmission Operator did not inform four or more other known impacted Balancing Authorities or more 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one impacted interconnected NERC registered entity or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned	The responsible entity did not notify two impacted interconnected NERC registered entities or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities,	The responsible entity did not notify three impacted interconnected NERC registered entities or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, monitoring and assessment capabilities, control equipment, and associated communication channels. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			outage of telemetering equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	whichever is less, of a planned outage of telemetering equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	less, of a planned outage of telemetering equipment, monitoring and assessment capabilities, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify four or more impacted interconnected NERC registered entities or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.
R11	Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not monitor its Balancing Authority Area, including the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	The Transmission Operator did not perform Real-time Assessments. OR, For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.
R18	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The responsible entity failed to operate to the most limiting parameter in instances where there was a difference in SOLs.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Transmission Operator did not have data exchange capabilities with two applicable entity, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Transmission Operator did not have data exchange capabilities with three applicable entity, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Transmission Operator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with two applicable entity, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with three applicable entity, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

White paper on SOL Exceedances to be placed here.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	~~April 2014~~TBD	Revisions ~~pursuant to~~under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

> **Rationale** - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)

> **Rationale** - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. ~~For~~Some examples include: ~~,~~1) ~~analysis of~~ analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service~~.~~, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - **4.5.** Load-Serving Entity
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards.~~ One petition ~~addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The~~ second petition ~~addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a~~ NOPR ~~proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these~~

~~aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The ~~as~~ new definition ~~now~~ covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act, or direct others ~~within its Transmission Operator Area~~ to act by issuing Operating Instructions, to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Transmission Operator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include~~,~~ but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Transmission Operator Area.

R2. Each Balancing Authority shall act, or direct others ~~within its Balancing Authority Area~~ to act by issuing Operating Instructions, to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Balancing Authority Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include~~,~~ but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act by issuing Operating Instructions to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Balancing Authority Area.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible ~~to do~~ due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator~~ in Requirement R3 citing one of the specific reasons shown in Requirement R3~~. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator~~ion~~ Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include~~,~~ but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued ~~in Requirement R3 citing one of the specific reasons shown in Requirement R3~~. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the ~~Transmission Operator~~Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include~~,~~ but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the ~~Balancing Authority~~Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. ~~'Effective' added as it makes no sense to do anything unless it will be effective in mitigating the problem.~~ 'Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures. These changes are in response to IERP recommendations.

R7. Each Transmission Operator ~~and Balancing Authority~~ shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its emergency procedures, unless such ~~actions~~assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator ~~and Balancing Authority~~ shall make available upon request, evidence that requested assistance, if able, was provided to other Transmission Operators unless such ~~actions~~assistance cannot be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. ~~Examples of such operations are relay or equipment failures; and changes in generation, Transmission, or Load.~~ *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and ~~negatively~~ impacted interconnected NERC registered entities of outages of telemetering ~~and telecommunication~~ equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and ~~negatively~~ impacted interconnected NERC registered entities of planned outages of telemetering ~~and telecommunication~~ equipment, control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities.

R10. Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to ~~maintain~~determine ~~reliability~~any System Operating Limit (SOL) exceedances within its Transmission Operator Area ~~including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area~~. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities, the status of Special protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to ~~maintain~~determine ~~reliability~~any System Operating Limit (SOL) exceedances within its Transmission Operator Area ~~including sub-100 kV facilities needed to maintain~~

~~reliability and the status of Special Protection Systems within its Transmission Operator Area~~ .

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall ensure~~perform~~ that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ~~conducted~~ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include~~,~~ but is not limited to~~,~~ dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a~~n~~ SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include~~,~~ but is not limited to~~,~~ dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when a~~n~~ SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the system to within limits when a~~n~~ SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunication, and Real-time Assessment capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System

Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunication, and Real-time Assessment capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunications, and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunications, and analysis capabilities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Operator~~ shall always operate to the most limiting parameter in instances where there is a difference in ~~derived limits~~ SOLs. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Operator~~ shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in ~~derived limits~~SOLs.

Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R2. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area (Balancing Authority Area). *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area (Balancing Authority Area). *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~Exception Reporting~~

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, ~~R13,~~ and R14 through R~~18~~20 and Measure M1 through M11, ~~M13,~~ and M14 through M~~18~~20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a~~n~~ SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act, or direct others within its Transmission Operator Area to act, to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Transmission Operator Area.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act, or direct others within its Balancing Authority Area to act, to ~~address~~ensure ~~its~~the reliability ~~functions within~~of its Balancing Authority Area.
R3	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an Operating

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-Time Operations					Instruction issued by its Transmission Operator~~ in Requirement R3 citing one of the specific reasons shown in Requirement R3~~.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator ~~or Balancing Authority~~ did not provide assistance to other Transmission Operators, if requested and able, when the requesting entity had implemented its emergency procedures, and such actions could have been physically

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the ~~affected~~known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit	The Transmission Operator did not inform two other known impacted Transmission Operators or more than 5% and less than or equal to 10% of the ~~affected~~known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other known impacted Transmission Operators or more than 10% and less than or equal to 15% of the ~~affected~~known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR,	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the ~~affected~~known impacted other Transmission Operators, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			such communications. OR, The Transmission Operator did not inform one other known impacted Balancing Authorities or 5% or less of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	OR, The Transmission Operator did not inform two other known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	The Transmission Operator did not inform three other known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform four or more other known impacted Balancing Authorities or more 15% of the known impacted other Balancing Authorities, whichever is less, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one ~~negatively~~ impacted interconnected NERC registered entity or 5% or less of the	The responsible entity did not notify two ~~negatively~~ impacted interconnected NERC registered entities or more than 5% and less than or equal to	The responsible entity did not notify three ~~negatively~~ impacted interconnected NERC registered entities or more than 10% and less than or equal to 15% of	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering ~~and telecommunication~~ equipment, monitoring and assessment capabilities,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering ~~and telecommunication~~ equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering ~~and telecommunication~~ equipment, monitoring and assessment capabilities, control equipment, and associated communication channels between the affected entities.	the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering ~~and telecommunication~~ equipment, monitoring and assessment capabilities, control equipment and associated communication channels between the affected entities.	control equipment, and associated communication channels. OR, The responsible entity did not notify four or more ~~negatively~~ impacted interconnected NERC registered entities or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering ~~and telecommunication~~ equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~maintain~~determine ~~reliability~~any System Operating Limit (SOL) exceedances within its Transmission Operator Area ~~including sub-100 kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area~~.
R11	Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	~~The Transmission Operator performed Real-time Assessments but did so at a periodicity of~~	~~The Transmission Operator performed Real-time Assessments but did so at a periodicity of~~	~~The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than~~	The Transmission Operator did not perform Real-time Assessments. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~more than 30 minutes but less than 35 minutes.~~ For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	~~more than or equal to 35 minutes and less than 40 minutes.~~ For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	~~or equal to 40 minutes and less than 45 minutes.~~ For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	~~The Transmission Operator performed Real-time Assessments but did so at a periodicity of more than or equal to 45 minutes.~~ For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a~~n~~ SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when a~~n~~ SOL had been exceeded.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunication, and Real-time Assessment capabilities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its ~~own~~ monitoring, telecommunications, and analysis capabilities.
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to operate to the most limiting parameter in instances where there was a difference in ~~derived limits~~SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one applicable entity, or 5% or less of the	The Transmission Operator did not have data exchange capabilities with two applicable entity, or more than 5% or less	The Transmission Operator did not have data exchange capabilities with three applicable entity, or more than 10% or less	The Transmission Operator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			applicable entities, whichever is less.	than or equal to 10% of the applicable entities, whichever is less.	than or equal to 15% of the applicable entities, whichever is less.	
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with two applicable entity, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with three applicable entity, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Balancing Authority did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

White paper on SOL Exceedances to be placed here.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for Requirement R1: Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis.

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirement R2: The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

Rationale for Requirement R3: Changes in response to IERP recommendation.

R3. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Rationale for Requirements R4 and R5: These Requirements were added to address IERP recommendations.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified impacted entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or e-mail records.

Rationale for Requirements R6 and R7: Added in response to SW Outage Report recommendation 1.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90 calendar days period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the impacted entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted NERC or more than 10% and less than or equal to 15% of the impacted entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more impacted NERC or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not notify one impacted entity or 5% or less	The Balancing Authority did not notify two impacted entities or more	The Balancing Authority did not notify three impacted entities or	The Balancing Authority did not notify four or more impacted entities or

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the impacted entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	than 5% and less than or equal to 10% of the impacted entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	more than 10% and less than or equal to 15% of the impacted entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as identified in Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
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2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revised under Project 2007-03.	Revised

3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

Rationale - ~~Changes made to the proposed definition were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Operational Planning Analyses contain sufficient details to result in an appropriate level of situational awareness. For example, analysis of post-Contingency phase angles may result in an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service post-Contingency.~~

~~Note that 'load' is not capitalized in load forecast as it is the whole phrase that is the item of interest and 'load forecast' is not a defined term.~~

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis.

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirement R2: The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include~~,~~ but it is not limited to~~,~~ plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

Rationale for Requirement R3: Changes in response to IERP recommendation.

R3. Each Transmission Operator shall notify impacted ~~NERC registered~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified impacted ~~NERC registered~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Rationale~~:~~ for Requirements R4 and R5: These Requirements were added ~~due~~ to address IERP recommendations.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify impacted ~~NERC registered~~ entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified impacted ~~NERC registered~~ entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs or e-mail records.

Rationale for Requirements R6 and R7: Added in response to SW Outage Report recommendation 1.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.

Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audit~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling ~~six month~~90 calendar days period for analyses, the most recent ~~three months~~90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area ~~will~~ exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted ~~NERC registered~~ entity or 5% or less of the impacted ~~NERC registered~~ entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two impacted ~~NERC registered~~ entities or more than 5% and less than or equal to 10% of the impacted ~~NERC registered~~ entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted NERC ~~registered entities~~ or more than 10% and less than or equal to 15% of the impacted ~~NERC registered~~ entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more impacted NERC ~~registered entities~~ or more than 15% of the impacted NERC ~~registered entities~~ identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority ~~does~~did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			notify one impacted ~~NERC registered~~ entity or 5% or less of the impacted ~~NERC registered~~ entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	notify two impacted ~~NERC registered~~ entities or more than 5% and less than or equal to 10% of the impacted ~~NERC registered~~ entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	notify three impacted ~~NERC registered~~ entities or more than 10% and less than or equal to 15% of the impacted ~~NERC registered~~ entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	notify four or more impacted ~~NERC registered~~ entities or more than 15% of the impacted ~~NERC registered~~ entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified in Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operational Reliability Data**
2. **Number: TOP-003-3**
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.
4. **Applicability:**
   - **4.1.** Transmission Operator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Load-Serving Entity
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:**

   All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Changes to proposed Requirement R1, Part 1.1 are in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data. The language has been moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability Coordinator.

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

Rationale for Requirement R5: Proposed Requirement R5, Part 5.3 is in **r**esponse to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3). OR, The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes ~~pursuant to~~under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**There are no new or revised definitions proposed in this standard revision.**~~

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operational Reliability Data**

2. **Number: TOP-003-3**

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   ~~**4.5.** Interchange Authority~~

   ~~**4.6.**~~**4.5.** Load-Serving Entity

   ~~**4.7.**~~**4.6.** Transmission Owner

   ~~**4.8.**~~**4.7.** Distribution Provider

5. **Effective Date:**

   All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Changes to proposed Requirement R1, ~~p~~Part 1.1 ~~is~~ are in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, ~~p~~Part 1.2 is in response to NOPR paragraph 78 on relay data. The ~~L~~language has been moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability Coordinator.

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to~~,~~ web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

Rationale for Requirement R5: Proposed Requirement R5, ~~p~~Part 5.3 is in **r**esponse to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, ~~Interchange Authority,~~ Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

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M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, ~~Interchange Authority,~~ Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, ~~Interchange Authority,~~ Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and ~~r~~Real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	N/A	~~N/A~~ The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	~~N/A~~ The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3). OR, The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 – March 24, 2014

First posting May 19, 2014 - July 2, 2014

Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes “Distribution Provider” to “Transmission Service provider”	Errata
1.1	October 29, 2008	Removed “proposed” from effective date BOT adopted errata changes: updated version number to “1.1”	Errata
1.1	May 13, 2009	FERC Approval	Revised
2	July 25, 2011	Revisions under Project 2006-06 to remove Requirement R7 to avoid duplication with IRO-014-2	Revised
3	July 6, 2012	Revisions to complete scope of revisions under Project 2006-06	Revised
3	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions as per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose:** To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**

> **Rationale:** Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5.

4.1. Reliability Coordinator

4.2. Transmission Operator

4.3. Balancing Authority

4.4. Generator Operator

4.5. Distribution Provider

5. **Effective Date:**

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

See the Project 2014-03 project page.

B. Requirements and Measures

> **Rationale**: The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

R1. Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act, by issuing Operating Instructions to ensure the reliability of its Reliability Coordinator Area.

> **Rationale for Requirements R2 and R3:** The addition of Transmission Service Provider to Requirements R2 and R3 allows for the retirement of IRO-004-2.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the

Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with the Reliability Coordinator's Operating Instructions, and compliance with the Operating Instructions could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1 .

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Formatted: Centered

Development Steps Completed

SAR posted for comment February 21, 2014 – March 24, 2014

First posting May 19, 2014 - July 2, 2014

Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
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4	TBD	Revisions under Project 2014-03	
~~3~~	~~August 4, 2011~~	~~Approved by Board of Trustees~~	
~~4~~	~~April 2014~~	~~Revisions as per Project 2014-03~~	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose:** To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**

> **Rationale:** Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5. ~~They do not show in this red-line as this red-line is based on IRO-001-3 as originally submitted by Project 2006-06 where they were initially removed.~~

4.1. Reliability Coordinator

4.2. Transmission Operator

4.3. Balancing Authority

4.4. Generator Operator

4.5. Distribution Provider

4.6. ~~Transmission Service Provider~~

5. **Effective Date:**

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

See the Project 2014-03 project page.

~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently~~

~~effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~

B. Requirements and Measures

Rationale: The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

R1. Each Reliability Coordinator shall act, or direct others to act, by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include~~,~~ but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted, or directed others to act, by issuing Operating Instructions to ensure the reliability of its Reliability Coordinator Area.

Rationale for Requirements R2 and R3: The addition of Transmission Service Provider to Requirements R2 and R3 allows for the retirement of IRO-004-2.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ and Distribution Provider shall have and provide evidence which may include~~,~~ but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R~~2~~1 ~~citing one of the specific reasons shown in Requirement R2~~. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ and Distribution Provider shall have and provide evidence which may include~~,~~ but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R~~2~~1 ~~citing one of the reasons shown in Requirement R2~~.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes:

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaints~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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1.4. Additional Compliance Information

None.

Table of Compliance Elements

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			Lower VSL	Moderate VSL	High VSL	Severe VSL
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R3	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction ~~I~~issued by its Reliability Coordinator in Requirement R~~2~~1 ~~citing one of the reasons shown in Requirement R2~~.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

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0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Deleted R2, M3 and associated compliance elements Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	
4	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

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Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-4
3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Reliability Coordinator
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   See the Project 2014-03 project page.

B. Requirements and Measures

> **Rationale**: Requirements R1 and R2 from IRO-002-2 have been added back into IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issues. The currently-effective requirement in IRO-002-2 has been separated into two parts (Requirements R1 and R2 below) to distinguish voice and data requirements. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

R1. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and real-time Assessments.

R2. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Rationale: Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Rationale for Requirement R4: Requirement R4 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

R4. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M4. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.

The Reliability Coordinator shall keep data or evidence for Requirement R4 and Measure M4 for the current calendar year and one previous calendar year.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is less.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R3	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Deleted R2, M3 and associated compliance elements Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	
4	April 2014	Revisions as per Project 2014-03	Revised
~~2~~	~~October 17, 2008~~	~~Adopted by NERC Board of Trustees~~	
~~2~~	~~March 17, 2011~~	~~Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)~~	
~~2~~	~~February 24, 2014~~	~~Updated VSLs based on June 24, 2013 approval.~~	
~~3~~	~~August 4, 2011~~	~~Approved by Board of Trustees~~	
~~4~~	~~April 2014~~	~~Revisions as per Project 2014-03~~	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**There are no new or revised definitions proposed in this standard revision.**~~

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**

2. **Number:** IRO-002-4

3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.

4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

   ~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the~~

~~opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~ See the Project 2014-03 project page.

B. Requirements and Measures

Rationale: Requirements R1 and R2 from IRO-002-2 have been added back into IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issues. The currently-effective requirement in IRO-002-2 has been separated into two parts (Requirements R1 and R2 below) to distinguish voice and data requirements. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

R1. ~~Each Reliability Coordinator shall have voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*~~

M1. ~~Each Reliability Coordinator shall have and provide upon request, evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators.~~

R2. Each Reliability Coordinator shall have data ~~links~~exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. ~~with Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area and with neighboring Reliability Coordinators.~~ *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ a document that lists its data ~~links~~exchange capabilities with Balancing Authorities~~, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities,~~ and Transmission Operators, ~~Transmission Owners, and Distribution Providers~~ and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and real-time Assessments.~~within its Reliability Coordinator Area and with neighboring Reliability Coordinators.~~

R3. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include~~,~~ but is not limited to~~,~~ a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Rationale: Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a~~n~~ SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

R4. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to ~~determine~~identify any ~~potential~~ System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area~~, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area~~. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M4. Each Reliability Coordinator shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to ~~determine~~identify any ~~potential~~ System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area~~, including sub-100 kV facilities~~

~~needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area~~.

Rationale for Requirement R5: Requirement R5 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

R5. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant ~~and highly reliable~~ infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M5. The Reliability Coordinator shall have, and provide upon request, evidence that could include~~,~~ but is not limited to~~,~~ Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes:

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaints~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.

The Reliability Coordinator shall keep data or evidence for Requirements R4 and R5 and Measures M4 and M5 for the current calendar year and one previous calendar year.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning, Same-Day Operations, Real-time Operations~~	~~High~~	~~N/A~~ ~~The Reliability Coordinator did not have voice communication facilities with one applicable entity, or 5% or less of the applicable entities, whichever is less, as specified in Requirement R1.~~	~~N/A~~ ~~The Reliability Coordinator did not have voice communication facilities with two applicable entities, or more than 5% and less than or equal to 10% of the applicable entities, whichever is less, as specified in Requirement R1.~~	~~N/A~~ ~~The Reliability Coordinator did not have voice communication facilities with three applicable entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, as specified in Requirement R1.~~	~~The Reliability Coordinator doesdid not have voice communication facilities with Transmission Operators, Balancing Authorities, and Generator Operators within its Reliability Coordinator Area or with neighboring Reliability Coordinators four or more applicable entities, or more than 15% of the entities, whichever is less, as specified in Requirement R1.~~
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	~~N/A~~ The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is less.	~~N/A~~ The Reliability Coordinator did not have data exchange capabilities with two applicable entity~~y~~ies, or more than 5% or less than or equal to 10% of the applicable entities, whichever is less.	~~N/A~~ The Reliability Coordinator did not have data exchange capabilities with three applicable entity~~y~~ies, or more than 10% or less than or equal to 15% of the applicable entities, whichever is less.	The Reliability Coordinator ~~does~~did not have data ~~link facilities~~exchange capabilities with ~~Balancing Authorities, Planning Coordinators, Transmission Planners, Generator Owners, Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Owners, and Distribution Providers within its Reliability Coordinator Area or with neighboring Reliability~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~Coordinators~~ four or more applicable entities or greater than 15% of the applicable entities, whichever is less.
R3	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R4	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to ~~determine~~identify any ~~potential~~ System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area~~, including sub-100 kV facilities needed to make this determination and~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~the status of Special Protection Systems in its Reliability Coordinator Area~~.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant ~~and highly reliable~~ infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting from May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-2
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirements R2 and R3: In response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirements R5 and R6: In Requirements R5 and R6 the use of the term ‘impacted’ and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted

Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90 calendar days period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30 calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted NERC registered entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s).
R4	Same-day Operations, Real-time Operations	High	For any sample 24-hour period within the 30-day retention period, the	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's	For any sample 24-hour period within the 30-day retention period, the	The Reliability Coordinator did not perform Real-time Assessments. OR

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan,

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability	when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Coordinator Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System Operating Limit (SOL) or	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the Emergency identified in Requirement R6 was prevented or mitigated.	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance	is less, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or	Requirement R6 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R6 was prevented or mitigated.	Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated.	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting from May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	~~April 2014~~TBD	~~Changes pursuant to~~Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**There are no new or revised definitions proposed in this standard revision.**~~

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-2
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

   ~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) ~~or~~and Interconnection Operating Reliability Limits (IROLs) within its ~~Reliability Coordinator~~ Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include~~,~~ but is not limited to~~,~~ dated power flow study results.

Rationale for Requirements ~~R2,~~ R3~~,~~ and R4: In response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

R2. ~~Each Reliability Coordinator shall review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

M2. ~~Each Reliability Coordinator shall have evidence that it reviewed the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities. Such evidence could include, but is not limited to, dated e-mail messages.~~

R3. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as ~~required~~performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 ~~and that~~while consider~~s~~ing the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include~~,~~ but is not limited to~~,~~ plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R4. Each Reliability Coordinator shall notify impacted ~~NERC registered~~ entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Reliability Coordinator shall have evidence that it notified impacted ~~NERC registered~~ entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R5. Each Reliability Coordinator shall ~~perform~~ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ~~conducted~~ensured that a Real-~~T~~time Assessment is performed at least once every 30 minutes. This evidence could include~~,~~ but is not limited to~~,~~ dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirements R5 and R6: ~~Language changed from IROL exceedance to Emergency, as Emergency is a stronger term which includes IROL exceedance and thus raises the bar for this requirement. Requirement R7 is the extension of Requirement R6 ensuring actions are taken to deal with the Emergency.~~ In Requirements ~~R6~~ R5 and ~~R8~~ R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R7. ~~Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*~~

M7. ~~Each Reliability Coordinator shall have evidence that it issued Operating Instructions, as necessary, to ensure that actions were taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6. Such evidence could include, but is not limited to, dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation.~~

R8. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M8. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaints~~

~~Exception Reporting~~

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R~~4~~3, R~~6~~5, and R6 ~~through R8~~ and Measures M1 through M~~4~~3, M~~6~~5, and M6 ~~through M8~~ for a rolling ~~six month~~ 90 calendar days period for analyses, the most recent ~~three months~~ 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R~~5~~4 and Measure M~~5~~4 for ~~the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of ninety calendar days~~ a rolling 30 calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not ~~have~~perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its ~~Reliability Coordinator~~ Wide Area will exceed any of its System Operating Limits (SOLs) ~~or~~and Interconnection Operating Reliability Limits (IROLs).
R2	~~Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not review the Operating Plans for next-day operations provided by its Transmission Operators and Balancing Authorities~~
R3	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						of its Operational Planning Analysis as ~~required~~performed in Requirement R1 ~~and~~while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
For the Requirements ~~R4,~~ R6~~,~~ and R9 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R4	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted ~~NERC registered~~ entity or 5% or less of the impacted NERC registered entities whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Reliability Coordinator did not notify two impacted ~~NERC registered~~ entities or more than 5% and less than or equal to 10% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to their role in	The Reliability Coordinator did not notify three impacted ~~NERC registered~~ entities or more than 10% and less than or equal to 15% of the impacted NERC registered entities whichever is less, identified in the Operating Plan(s) as to	The Reliability Coordinator did not notify four or more impacted ~~NERC registered~~ entities or more than 15% of the impacted NERC registered entities identified in the Operating Plan(s) as to their role in the plan(s).

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				the plan(s).	their role in the plan(s).	
R5	Same-day Operations, Real-time Operations	High	~~The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than 30 minutes but less than 35 minutes as averaged over the 30-day data retention period.~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that	~~The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 35 minutes and less than 40 minutes as averaged over the 30-day data retention period.~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	~~The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 40 minutes and less than 45 minutes as averaged over the 30-day data retention period.~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute	The Reliability Coordinator did not perform Real-time Assessments. OR ~~The Reliability Coordinator performed Real-time Assessments but did so at a periodicity of more than or equal to 45 minutes as averaged over the 30-day data retention period.~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			24-hour period.		periods within that 24-hour period.	
R6	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the results of its Real-time Assessment	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	is less, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.	within its Reliability Coordinator Wide Area.
~~R7~~	~~Same-Day Operations, Real-time Operations~~	~~High~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to issue Operating Instructions, as necessary, to ensure that actions are~~were ~~taken to deal with the~~

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.~~
R8	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is less, when the System	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the Emergency identified in Requirement R6	Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability	Coordinator Area whichever is less, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the	Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~has been~~was prevented or mitigated.	Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated.	System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 ~~has been~~was prevented or mitigated.	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

~~None~~

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval.	
2	April 2014	Revisions pursuant to Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection

2. **Number:** IRO-010-2

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

> **Rationale for Applicability changes:** Changes were made to applicability based on IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.
>
> The Interchange Authority was removed because activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.
>
> The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard.

4. **Applicability**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Load-Serving Entity.

   4.6. Transmission Operator.

   4.7. Transmission Owner.

   4.8. Distribution Provider.

5. **Proposed Effective Date:**

   Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background

See Project 2014-03 project page.

B. Requirements

Rationale:

Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is less, that have data required by the Reliability Coordinator's	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Reliability	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Reliability Coordinator's Operational

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	**Moderate**	**High**	**Severe**
			time Assessments.	Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval.	
2	~~April 2014~~TBD	Revisions ~~pursuant to~~under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

~~**There are no new or revised definitions proposed in this standard revision.**~~

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability**
   - **4.1.** Reliability Coordinator.
   - **4.2.** Balancing Authority.
   - **4.3.** ~~Planning Coordinator.~~
   - **4.4.** ~~Transmission Planner.~~
   - **4.5.** Generator Owner.
   - **4.6.** Generator Operator.
   - **4.7.** Load-Serving Entity.
   - **4.8.** Transmission Operator.
   - **4.9.** Transmission Owner.
   - **4.10.** Distribution Provider.

Rationale for Applicability changes: Changes to applicability were made based on the IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.

The Interchange Authority was removed activities assigned to the Interchange Authority in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.

The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard. ~~The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.~~

5. **Proposed Effective Date:**

Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background

~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR~~

~~issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~See Project 2014-03 project page.

B. Requirements

Rationale ~~for Requirement R1~~:

Proposed Requirement R1, ~~p~~Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining sub-100 kV and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, ~~p~~Part 1.2 is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R~~1~~3, ~~p~~Part ~~1.7~~3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: ~~Medium~~Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: ~~Medium~~Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include~~,~~ but is not limited to~~,~~ web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, ~~Planning Coordinator, Transmission Planner,~~ Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, ~~Planning Coordinator, Transmission Planner,~~ Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include~~,~~ but is not limited to~~,~~ electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	~~Medium~~Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include ~~four or more~~any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses,

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	~~Medium~~Low	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is less, that have data required by the Reliability	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Reliability Coordinator's

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
			monitoring, and Real-time Assessments.	Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in ~~p~~Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in ~~p~~Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in ~~p~~Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Hyphenated "30-day" when used as adjective. 3. Changed standard header to be consistent with standard "Title." 4. Initial capped heading "Definitions of Terms Used in Standard." 5. Added "periods" to items where appropriate. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all words that are not "defined" terms — drafting team, self-certification. 8. Changed apostrophes to "smart" symbols. 9. Added comma in all word strings "Procedures, Processes, or Plans," etc. 10. Added hyphens to "Reliability Coordinator-to-Reliability Coordinator" where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06
2		Revised under Project 2006-06	Revised
2	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators

2. **Number:** IRO-014-3

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.

   On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.

   On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.

B. Requirements and Measures

Rationale for Requirement R1: Grammatical changes for consistency with defined terms to Requirement R1.

Deletions are due to duplication with proposed IRO-008-2, Requirements R4 and R6 and proposed IRO-010-3.

Other changes are grammatical for clarity.

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. Criteria and processes for notifications .

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. Provisions for periodic communications to support reliable operations.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that the Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

Rationale: Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.

R4. Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

R5. Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall have evidence that it developed an action plan during those instances where impacted Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation.

R6. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each impacted Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who has identified the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

Rationale for Requirement R7: Language added for consistency with proposed TOP-001-3, Requirement R7.

R7. Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M7. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 and R2 and Measures M1 and M2.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement R5 and Measure M5.
- Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirements R6 and R8 and Measures M6 and M8.
- Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R7 and R9 and Measures M7 and M9.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability. OR, The Reliability Coordinator failed to implement its Operating Procedures, Operating processes, or Operating Plans when activities required notification, or coordination of actions with impacted adjacent Reliability Coordinators to support

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet one of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet two of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet all three of the criteria specified in Requirement R2.
For the Requirement R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identified the Emergency in its Reliability Coordinator Area failed to develop an action plan to resolve the Emergency during an instance where impacted Reliability Coordinators disagreed on the existence of Emergency.
R6	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identified the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Emergency during an instance where Reliability Coordinators disagreed on the existence of the Emergency.
R7	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions could not physically be implemented or would violate safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06
2		Revised under Project 2006-06	Revised
2	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions under Project 2014-03	Revised
~~3~~	~~August 4, 2011~~	~~Approved by Board of Trustees~~	
~~4~~	~~April 2014~~	~~Revisions per Project 2014-03~~	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators

2. **Number:** IRO-014-3

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

   ~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC~~

~~standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Grammatical changes for consistency with defined terms to Requirement R1.

Deletions are due to duplication with proposed IRO-008-2, Requirements R4 and R6 and proposed IRO-010-3.

Other changes are grammatical for clarity.

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact ~~other~~adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. ~~Communications and nN~~ Criteria and processes for notifications~~, and the process to follow in making those notifications~~.

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. ~~Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.~~

1.6. Provisions for ~~weekly conference calls~~ periodic communications to support reliable operations.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that impact ~~other~~adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low~~er~~] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that the Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include~~,~~ but is not limited to~~,~~ dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

~~**R3.** Each Reliability Coordinator shall make notifications and exchange reliability–related information with other impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*~~

~~**R4.** Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it made notifications and exchanged reliability–related information with impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~

~~**R5.** Each Reliability Coordinator shall participate in agreed upon conference calls, at least weekly (per Requirement R1, Part 1.6) with other Reliability Coordinators within the same Interconnection. *[Violation Risk Factor: Lower][Time Horizon: Same-Day Operations]*~~

~~**R6.** Each Reliability Coordinator shall have and provide evidence which may include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it participated in agreed upon (at least weekly) conference calls with other Reliability Coordinators within the same Interconnection.~~

Rationale: Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

~~R7.~~R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include~~,~~ but is not limited to~~,~~ operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.

~~R8.~~R4. Each impacted Reliability Coordinator shall operate as though the ~~problem~~Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include~~,~~ but is not limited to~~,~~ operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

~~R9.~~R5. Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall have evidence that it developed an action plan during those instances where impacted Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include~~,~~ but is not limited to~~,~~ operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation.

~~R10.~~R6. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each impacted Reliability Coordinator shall have and provide evidence which may include~~,~~ but is not limited to~~,~~ operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who has identified the Emergency when Reliability

Rationale for Requirement R9: Language added for consistency with proposed TOP-001-3, Requirement R7.

Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

~~**R9**~~**R7**. Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting ~~entity~~Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically ~~be~~ implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M7. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include~~,~~ but is not limited to~~,~~ dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes:

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaints~~

~~Exception Reporting~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 and R2~~, and R9~~ and Measures M1 and M2~~, and M9~~.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement~~s R3, R4, and~~ R5 and Measure~~s M3, M4, and~~ M5.
- Each Reliability Coordinator shall retain 3-~~-~~calendar years plus current calendar year of evidence for Requirements R6~~, R7,~~ and R8 and Measures M6~~, M7,~~ and M8.
- Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R7 and R9 and Measures M7 and M9.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.~~6~~5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.~~6~~5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.~~6~~5.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability. OR, The Reliability Coordinator failed to implement its Operating Procedures, Operating processes, or Operating Plans when activities required notification, or coordination of actions with impacted adjacent Reliability Coordinators to support

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	~~The Reliability Coordinator has the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet one of the criteria.~~ N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet ~~two~~one of the criteria specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet ~~three~~two of the criteria specified in Requirement R2.	~~The Reliability Coordinator does not have Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~ The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to meet all three of the criteria specified in Requirement R2.
For the Requirement~~s R3 and~~ R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	~~Operations Planning, Same-Day Operations,~~	~~Medium~~	~~The Reliability Coordinator did not make notifications and exchange reliability-related information with~~	~~The Reliability Coordinator did not make notifications and exchange reliability-related information with~~	~~The Reliability Coordinator did not make notifications and exchange reliability-related information with~~	~~The Reliability Coordinator did not make notifications and exchange reliability-related information with~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Real-time Operations~~		~~one impacted Reliability Coordinator in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~	~~two impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~	~~three impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~	~~four or more impacted Reliability Coordinators in accordance with the Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1.~~
R4	~~Same-Day Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to participate in an agreed upon (at least weekly) conference call with other Reliability Coordinators within the same Interconnection.~~
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.
R6	Operations Planning,	High	N/A	N/A	N/A	The Reliability Coordinator failed to

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-Day Operations, Real-time Operations					operate as though the ~~problem~~Emergency exist~~s~~ed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R7	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identified the Emergency in its Reliability Coordinator Area failed to develop an action plan to resolve the Emergency during an instance where impacted Reliability Coordinators disagreed on the existence of Emergency.
R8	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identified the Emergency during an instance where

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Reliability Coordinators disagreed on the existence of the Emergency.
R9	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting ~~entity~~Reliability Coordinator has implemented its emergency procedures, unless such actions could not ~~be~~ physically be implemented or would violate safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Outage Coordination**
2. **Number: IRO-017-1**
3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Planning Coordinator
   - **4.5.** Transmission Planner
5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and generator outages within its Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in its Reliability Coordinator outage coordination process. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R3: Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R4: The SDT has re-written Requirement R4 to show that the process starts with the Planning Assessments created by the Planning Coordinator and Transmission Planner and then those Planning Assessments are reviewed and reconciled as needed with the Reliability Coordinator. This is in response to comments in paragraph 90 of the FERC NOPR about directly involving the Reliability Coordinator in the planning process for periods beyond the present one year outreach. The re-write should not be construed as relieving the Reliability Coordinator of responsibilities in this area but simply as a reflection of how the process actually starts.

In the future, the SDT believes that such coordination should take place in the TPL standards and to support that position, the SDT has created an item in a draft SAR for TPL-001-4 that would revise Requirement R8 to make the Reliability Coordinator an explicit party in the review process described there.

In addition, the SDT will submit a request to the Functional Model Working Team to adjust the roles and responsibilities of the Reliability Coordinator to this new paradigm.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it jointly developed solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing all four of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator outage coordination process.
R3	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its Planning Assessment to impacted Reliability Coordinators.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~first~~second posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
~~Additional ballot~~	~~August 2014~~
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Outage Coordination**

2. **Number: IRO-017-1**

3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Transmission Operator

   4.3. Balancing Authority

   4.4. Planning Coordinator

   4.5. Transmission Planner

5. **Effective Date:**

   The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that~~

~~the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel and the SW Outage Report.~~See Project 2014-03 project page.

B. Requirements and Measures

Rationale: This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s)~~ prior to submitting to Reliability Coordinators~~.

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and generator outages within its ~~Reliability Coordinator~~ Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Note on part 1.5 ~~– Operations planning horizon is next-day to one year out. This requirement part will allow for Reliability Coordinators to request seasonal planning assessments if so desired.~~ After reviewing industry comments, the SDT does not believe this is needed for seasonal assessments. The Reliability Coordinator can always request seasonal assessments if it believes they are necessary for reliability.

1.5. ~~Document and maintain the specifications for outage analysis during the operations planning horizon.~~

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in ~~follow~~ its Reliability Coordinator outage coordination process. *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in ~~followed~~ its Reliability Coordinator outage coordination process. Such evidence could include~~,~~ but is not limited to~~,~~ web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R3: Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: Operations Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include~~,~~ but is not limited to~~,~~ web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R4: The SDT has re-written Requirement R4 to show that the process starts with the Planning Assessments created by the Planning Coordinator and Transmission Planner and then those Planning Assessments are reviewed and reconciled as needed with the Reliability Coordinator. This is in response to comments in paragraph 90 of the FERC NOPR about directly involving the Reliability Coordinator in the planning process for periods beyond the present one year outreach. The re-write should not be construed as relieving the Reliability Coordinator of responsibilities in this area but simply as a reflection of how the process actually starts.

In the future, the SDT believes that such coordination should take place in the TPL standards and to support that position, the SDT has created an item in a draft SAR for TPL-001-4 that would revise Requirement R8 to make the Reliability Coordinator an explicit party in the review process described there.

In addition, the SDT will submit a request to the Functional Model Working Team to adjust the roles and responsibilities of the Reliability Coordinator to this new paradigm.

R4. Each ~~Reliability Coordinator,~~ Planning Coordinator~~,~~ and Transmission Planner shall ~~coordinate~~jointly develop solutions with~~in~~ ~~the~~its respective Reliability Coordinator(s) ~~Area~~ for identified issues or conflicts with planned outages in ~~the~~its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning~~ Long-term Planning]*

M4. Each ~~Reliability Coordinator,~~ Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it ~~coordinated~~jointly developed solutions with~~in~~ ~~the~~its respective Reliability Coordinator(s) ~~Area~~ for identified issues or conflicts with planned outages in ~~the~~its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include~~,~~ but is not limited to~~,~~ web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and ~~Enforcement~~Assessment Processes

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	~~Low~~Medium	~~N/A~~ The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	~~N/A~~ The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	~~N/A~~ The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing all four of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
R2	Operations Planning	~~Low~~Medium	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not perform the functions specified in ~~follow~~ its Reliability Coordinator outage coordination process.
R3	Operations Planning	~~Low~~Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Planning Assessment to impacted Reliability Coordinators.
R4	Operations Planning	~~Low~~Medium	N/A	N/A	N/A	The ~~Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner did not ~~coordinate~~jointly develop solutions with~~in~~ ~~the~~its respective Reliability Coordinator(s) ~~Area~~ for identified issues or conflicts with planned outages in ~~the~~its Planning Assessment for the Near-term Transmission Planning Horizon.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Definitions

Project 2014-03 Revisions to TOP/IRO Reliability Standards

As part of the work in Project 2014-03 Revisions to TOP/IRO Reliability Standards, the SDT is proposing changes to two existing definitions: Operational Planning Analysis and Real-time Assessment.

The currently-effective definition of Operational Planning Analysis is: "*An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).*"

The proposed version of the definition of Operational Planning Analysis is: "*An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)*"

The currently-effective definition of Real-time Assessment is: "*An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.*"

The proposed version of the definition of Real-time Assessment is: "*An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*"

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, TOP-003-3, IRO-002-4, IRO-008-2, and IRO-010-2. These definitions are not used in any other standards, either currently-effective or in development in any other project.

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Definitions

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The proposed version of the definition of Real-time Assessment is: "*An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)*"

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

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Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**
    - TOP-001-1a Reliability Responsibilities and Authorities
    - TOP-002—2.1b Normal Operations Planning
    - TOP-003-1 Planned Outage Coordination
    - TOP-004-2 Transmission Operations
    - TOP-005-2a Operational Reliability Information
    - TOP-006-2 Monitoring System Conditions
    - TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
    - TOP-008-1 Response to Transmission Limit Violations
    - IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
    - IRO-002-2 Reliability Coordination — Facilities
    - IRO-003-2 Reliability Coordination – Wide Area View
    - IRO-004-2 Reliability Coordination – Operations Planning
    - IRO-005-3.1a Reliability Coordination — Current Day Operations
    - IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
    - IRO-010-1a Reliability Coordinator Data Specification and Collection
    - IRO-014-1 Coordination Among Reliability Coordinators
    - IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
    - IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
    - PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project. Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:
   - TOP-001-2 Transmission Operations
   - TOP-002-3 Operations Planning
   - TOP-003-2 Operational Reliability Data
   - IRO-001-3 Reliability Coordination - Responsibilities and Authorities
   - IRO-002-3 Reliability Coordination — Analysis Tools
   - IRO-005-4 Reliability Coordination — Current Day Operations
   - IRO-014-2 Coordination Among Reliability Coordinators
   - PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the currently enforceable standards and definitions would remain effective until those approvals have occurred, and the new or revised standards in Project 2014-03 shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective three months earlier, in order to provide recipients of data requests from their Reliability Coordinators, Transmission Operators, and/or Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. **If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:**

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**

- TOP-001-1a Reliability Responsibilities and Authorities
- TOP-002—2.1b Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2a Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 Response to Transmission Limit Violations
- IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
- IRO-002-2 Reliability Coordination — Facilities
- IRO-003-2 Reliability Coordination – Wide Area View
- IRO-004-2 Reliability Coordination – Operations Planning
- IRO-005-3.1a Reliability Coordination — Current Day Operations
- IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a Reliability Coordinator Data Specification and Collection
- IRO-014-1 Coordination Among Reliability Coordinators
- IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project.~~, and u~~Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:

- TOP-001-2 Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data
- IRO-001-3 Reliability Coordination - Responsibilities and Authorities
- IRO-002-3 Reliability Coordination — Analysis Tools
- IRO-005-4 Reliability Coordination — Current Day Operations
- IRO-014-2 Coordination Among Reliability Coordinators
- PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the ~~intent is that the~~ currently enforceable standards and definitions would remain effective until those approvals ha~~d~~ve occurred, and the new or revised standards in Project 2014-03 ~~would~~shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the “TOP Standards”) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the “IRO Standards”) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.” For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective ~~two~~three months earlier, in order to provide recipients of data requests from their ~~RCs~~Reliability Coordinators, ~~TOPs~~Transmission Operators, and/or ~~BAs~~Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- ~~Interchange Authority~~
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- ~~Transmission Service Provider~~
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. ~~I~~If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is ~~ten (10)~~nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~day immediately prior to the Effective Date in the particular jurisdiction in which the new standard or definition is becoming effective.~~

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition ~~standards~~ shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the “TOP Standards”) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the “IRO Standards”) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.” For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits (“SOLs”), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the recommendations from the Independent Expert Review Project and the SW Outage Report will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards to address concerns expressed in the NOPR a. Consider the inputs from technical conferences 2. Consider the recommendations in the Independent Expert Review Report and the SW Outage Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Preserve the intent of the reliability objectives in the current, approved standards so that no reliability gaps are created 5. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 6. Address the directives from Order 693 originally assigned to Projects 2006-06 and 2007-03.

SAR Information

7. Address the following directive from Order 693, paragraph 1855:
“Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator’s monitoring responsibilities.”
8. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements.
9. Address the issue of outage coordination as pointed out by the Independent Experts Review Panel through the creation of a new standard.
10. Address the recommendations of the IRO Five Year Review Team (Project 2012-09) for the IRO standards revised in this project.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5 IRO-008-1 IRO-009-1 IRO-010-1a IRO-015-1 IRO-016-1	May need to be reviewed for language and terminology consistency with revisions made in this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A

Regional Variances	
SPP	N/A
WECC	N/A

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | Updated August 2014

This mapping document showing the translation of Requirements in the following currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions[1]
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

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[1] TOP-006-2 is the currently enforceable version of this standard; TOP-006-3 was developed in response to a request for interpretation seeking clarification of Requirement R1 and does not substantively change the Requirements of TOP-006-2. In its NOPR proposing to remand the TOP and IRO standard, FERC proposed to approve TOP-006-3. The drafting team has mapped the Requirements in the new standards to TOP-006-3 because the Parts of Requirement R1 in TOP-006-3 more clearly delineate which entity has responsibility.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** Reliability Coordinators must comply with mandatory approved standards. The SDT proposes retiring the requirement, consistent with P81, as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission Operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or direct others to act. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	**Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed COM-001-2 Requirement R1 for voice links and proposed IRO-002-2 Requirement R1 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed COM-001-2, Requirement R1:** **R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R1:** **R1.** Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Approved PER-004-2, Requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, Part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, Part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability	This requirement is replaced by proposed COM-001-2 Requirement R1 and proposed IRO-002-4 Requirement R2. **Proposed COM-001-2, Requirement R1:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	**R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R2:** **R2**. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirements R3 and R4:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to	This requirement is replaced by proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R4:** **R4**. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R3 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have	This requirement is replaced by proposed IRO-002, Requirement R2 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R2:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
procedures in place to mitigate the effects of analysis tool outages.	**R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunications, monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R3 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	Addition of Transmission Service Provider to proposed IRO-001-4, Requirements R2 and R3 allows for the retirement of this requirement. **Proposed IRO-001-4, Requirement R2:** R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-4, Requirement R3:** R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R2 citing one of the specific reasons shown in Requirement R2.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	Replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and	The first sentence is replaced by proposed IRO-002-4, Requirement R3. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R3**:

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by approved EOP-010-1, Requirements R1 through R3. **Approved EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R3, R5 and R6. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-34 Requirements R3 and R4. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R3:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-010-2, Requirements R1, Part 1.2, and R3.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	**Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-010-4, Requirement R1, Part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:**

<table>
<tr><th colspan="2">Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td></td><td>R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.

Proposed TOP-001-3, Requirement R18:
R18. Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs.</td></tr>
<tr><td>R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.</td><td>This requirement is replaced by proposed MOD-001-2, Requirement R2.

Proposed MOD-001-2, Requirement R2:
R2. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider’s current practices for determining AFC or ATC values.
2.1. Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC:
2.1.1. The simulation of transfers performed through the adjustment of generation, Load, or both;
2.1.2. Transmission topology, including, but not limited to, additions and retirements;
2.1.3. Expected transmission uses;
2.1.4. Planned outages;
2.1.5. Parallel path (loop flow) adjustments;
2.1.6. Load forecast; and
2.1.7. Generator dispatch, including, but not limited to, additions and retirements.
2.2. Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.</td></tr>
<tr><td>R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall</td><td>The requirement is replaced by proposed IRO-008-2, Requirements R3, R5, and R6.

Proposed IRO-008-2, Requirement R3:</td></tr>
</table>

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	**R3.** Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed IRO-008-2, Requirement R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R4. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R3 and R5. **Proposed IRO-008-2, Requirements R3 and R5:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). Proposed IRO-008-2, R6: **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: **R1.1.** List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. **R1.2.** Mutually agreeable format. **R1.3.** Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). **R1.4.** Process for data provision when automated Real-Time system operating data is unavailable.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **1.3** A periodicity for providing data. **1.4** The deadline by which the respondent is to provide the indicated data. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.	This requirement is replaced by proposed IRO-010-2, Requirement R2. **Proposed IRO-010-2, Requirement R2:** **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Criteria and processes for notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Provisions for periodic communications to support reliable operations.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1, Part 1.5:** **R1, Part 1.5:** Provisions for periodic communications to support reliable operations.
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R3.1**. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	This requirement is replaced by approved PRC-001-1.1, Requirement R3. **Approved PRC-001-1.1, Requirement R3:** **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **3.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **3.2** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R3 through R6 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. **Proposed IRO-014-3, Requirement R4:** **R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R5:** **R5**. Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R6:** **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014 as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	**R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-2, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-2, R2: **Proposed IRO-001-2, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-2, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R3: **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7.** Each Transmission Operator shall assist other Transmission Operators, if requested and available, provided that the requesting entity has implemented its emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R7.1 For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – reactive power: Replaced by approved VAR-001-3, Requirement R8 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-3, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Approved VAR-001-3, Requirement R8:** **R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits. **Approved VAR-001-3, Requirement R12:** **R12**. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved IRO-009-1, Requirement R1: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	The Transmission Operator and balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:**

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-3, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-003-3, Requirement R1, Part 1.1.1, and proposed TOP-002-4, Requirement R4. **Approved INT-003-3, Requirement R1:** **R1.** Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. R1.1.1. Interchange Schedule start and end time. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing Authorities have been removed from the applicability of this requirement. SOLs and IROLs

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13. Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs. Second sentence – SOLs are set by the Transmission Operator in approved FAC-014-2, Requirement R2 according to the methodology distributed by the Reliability Coordinator in approved FAC-011-2, Requirement R4, Part 4.3. This should assure that SOLs are consistent for common facilities. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved FAC-014-2, Requirement R2:**

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: 4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:**

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<tr><th colspan="2">Standard TOP-002-2a — Normal Operations Planning</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td></td><td>2.4 Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.</td></tr>
<tr><td>R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.</td><td>This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5.

Proposed TOP-001-3, Requirement R2:

R2. Each Balancing Authority shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area.

Proposed TOP-003-3, Requirement R2:

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.

Proposed TOP-003-3, Requirement R5:

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.</td></tr>
<tr><td>R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

14.1 Changes in real and reactive output capabilities. (Retired August 1, 2007)</td><td>This requirement is replaced by proposed TOP-003-3, Requirement R5.

Proposed TOP-003-3, Requirement R5:
R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …</td></tr>
</table>

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
14.2 Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	The SDT believes that modeling starts with the model created by the Planning Coordinator and model verification for the Planning Coordinator is addressed in proposed MOD-033-1, Requirements R1 and R2. Therefore, the SDT is proposing to retire this requirement. **Proposed MOD-033-1, Requirement R1:** **R1**. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: **1.1** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation; **1.2** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs; **1.3** Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and **1.4** Guidelines to resolve the unacceptable differences in performance identified under Part 1.3. **Proposed MOD-033-1, Requirement R2:** **R2.** Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar

Standard TOP-002-2a — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, Requirement R2. **Proposed IRO-008-2, Requirement R2:** **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14 and proposed TOP-002-4, Requirement R2. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed definition:**

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. **Approved FAC-014-2, Requirement R2:**

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System. **Proposed TOP-001-3, Requirement R12:** **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed definition:**

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-3, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R12 and R14. **R6.2** has been replaced by proposed TOP-001-3, Requirement R8.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
6.1 Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	**R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-3, Requirement R1:** **R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, Part 3.3:** **3.3** A mutually agreeable security protocol **Proposed TOP-003-3, Requirement R5, Part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data**,"** unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R3, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, Part 1.2; proposed TOP-003-3, Requirement R1, Part 1.2; and proposed TOP-003-3, Requirement R2, Part 2.2. **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to:

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R2, Part 2.2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R3.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
in operating conditions and to indicate, if appropriate, the need for corrective action.	**Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Metering accuracy for Balancing Authorities is covered under approved BAL-005 -0.2b, Requirement R17 and thus this requirement can be retired from the TOP standards. The SDT believes that this requirement truly pertains to the Balancing Authority and that the Transmission Operator is the actual entity who will be taking care of many of the meters mentioned in approved BAL-005-0.2b. Therefore, the SDT is proposing to retire the Transmission Operator part of this requirement. **Approved BAL-005-0.2b, Requirement R17:** **R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R3, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R3**:

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R5 and R6. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an SOL has been exceeded. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and other impacted Reliability Coordinators when the results of a Real-time Assessment indicate an actual or expected condition that

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R6. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24 hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their Normal Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Emergency (short-term) Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this

approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the limiting SOLs. Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the practices and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent unit/intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the

maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.

4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level for which a post-Contingency solution can be reached. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

<u>Facility Rating Exceedance</u>

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

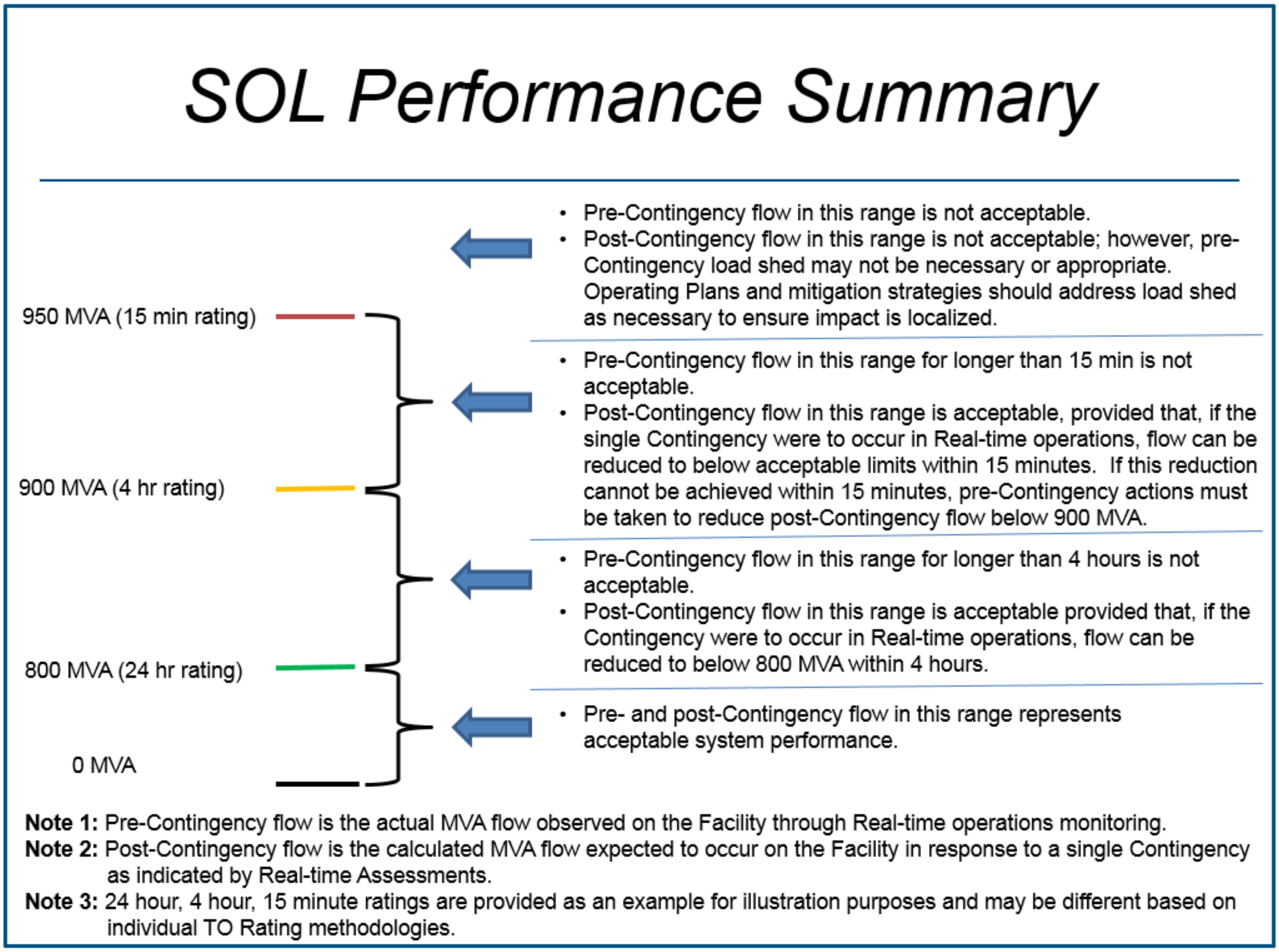

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

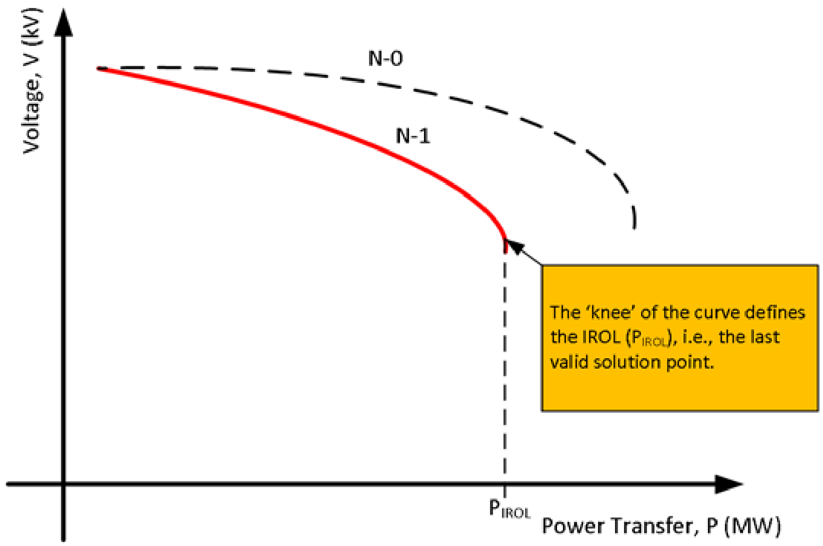

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal Limit Exceeded	Pre-Contingency Loading	Post-Contingency Loading
Normal (24 hr)	**Non-cost actions, off-cost actions, emergency procedures except load shed consistent with timelines identified in Operating Plan.**	**Trend – continue to monitor. Take non-cost actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.**
Emergency (4 hr)	**All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.**	**Use all effective actions and emergency procedures except load shed consistent with timelines identified in Operating Plan.**
Emergency (15 min)	**All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.**	**All of the above however, load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.**

Legend
NON-COST
OFF-COST
LOAD SHEDDING

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.

- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

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As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal ~~(continuous)~~ and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). ~~Typical Normal (continuous) Ratings are~~A 24 hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature~~s~~. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their Normal ~~(continuous)~~ Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Emergency (short-term) Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are~~is~~ consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this

approach may~~does~~ not capture the complete intent of the SOL concept ~~believing the intent of~~within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on ~~include Facility Ratings (~~Normal ~~(continuous)~~ and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the limiting SOLs. Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or ~~s~~Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the practices and mechanisms employed~~ed~~ by that entity. For example, one ~~TOP~~Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal ~~(continuous)~~ and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**

Transmission Operators ~~shall~~ establish SOLs to prevent unit/intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met~~for which a post-Contingency solution can be reached~~. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.

4. **Voltage Stability Limits:**
   Transmission Operators typically~~shall~~ stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level for which a post-Contingency solution can be reached. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

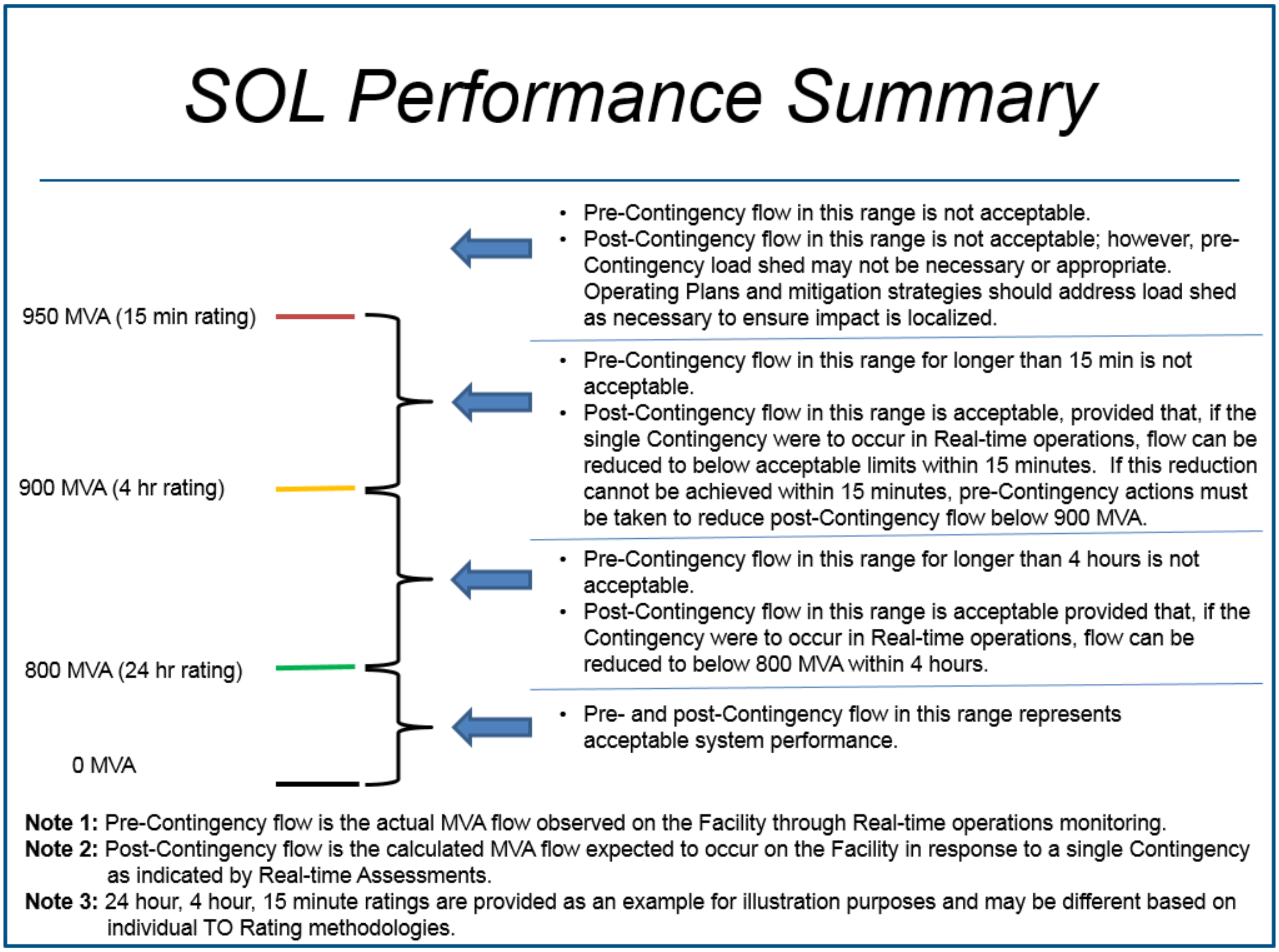

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, ~~TOPs~~Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency ~~l~~Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed ~~l~~Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved ~~NERC Standard~~ FAC-008-3~~Both normal and emergency voltage limits are established that respect the Transmission Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3~~. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

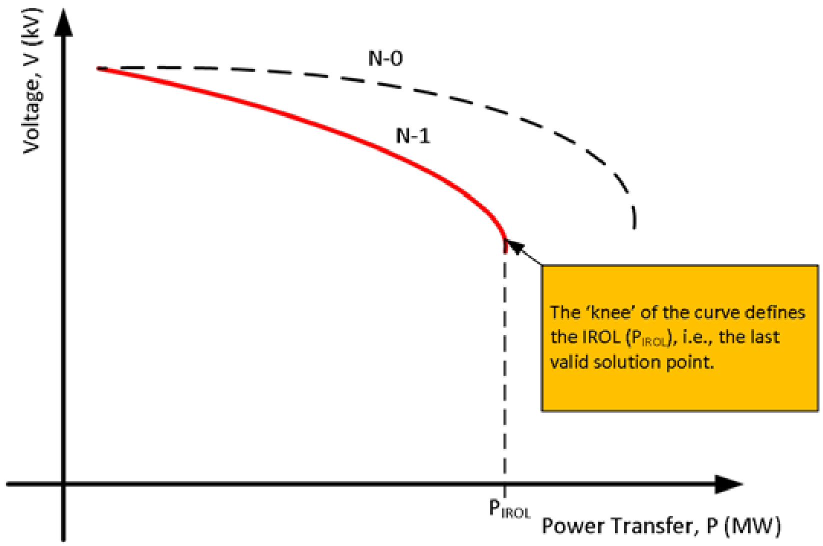

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:
When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal ~~(continuous)~~ and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal Limit Exceeded	Pre-Contingency Loading	Post-Contingency Loading
Normal (24 hr)	Non-cost actions, off-cost actions, emergency procedures except load shed consistent with timelines identified in Operating Plan.	Trend – continue to monitor. Take non-cost actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.
Emergency (4 hr)	All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.	Use all effective actions and emergency procedures except load shed consistent with timelines identified in Operating Plan.
~~Load Shed~~Emergency (15 min)	All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.	All of the above however, load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.

Legend
NON-COST
OFF-COST
LOAD SHEDDING

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through ~~contracted~~ third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through ~~contracted~~ third-party services.)

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a S~~s~~ystem O~~o~~peratoring~~ing~~ to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not R~~r~~eal-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the B~~b~~ulk E~~e~~lectric S~~s~~ystem.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment~~,~~ life or other physical or safety limitations for the equipment involved.

TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

Plan and Operate within all System Operating Limits

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

SDT Consideration:

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure that actions are taken to deal with the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

<u>SDT consideration:</u>

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

> Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.
>
> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, to ensure that it is able to perform its reliability functions.

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

SDT consideration:

See previous response.

Compliance with Reliability Directives

Para 64: The currently-effective TOP Reliability Standards use “reliability directive,” which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of “Reliability Directive” appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

SDT consideration:

The Project 2014-03 SDT is replacing the term ‘reliability directive’ with the defined term ‘Operating Instruction’ throughout the proposed standards. The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered.

Para 65: NERC’s TOP and IRO petitions do not explain the proposed, defined term “Reliability Directive,” or why compliance with a transmission operator’s directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. The proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that sub-100 kV data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.
>
> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT discussed this concern and concluded that an explicit requirement to use the data was an unnecessary administrative concern.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. These requirements will dictate what external data a Transmission Operator needs to acquire.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

See previous responses for this heading.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

> How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?
>
> > SDT consideration:
> >
> > The Project 2014-03 SDT has added all SOLs thus addressing this issue.
>
> For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?
>
> > SDT consideration:
> >
> > The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.
> >
> > In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.
> >
> > > Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2: The Reliability Coordinator's SOL Methodology shall include a

requirement that SOLs provide BES performance consistent with the following:
2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers this situation.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R5 that uses only actual and projected Emergency covering all time horizons.

> Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

<u>SDT consideration</u>:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

Proposed IRO-014-2, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
1.2 Specify outage submission timing requirements.
1.3 Define the process to evaluate the impact of Transmission and generator outages within its Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, Part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, sub-100 kV data, and applicable relay data are included.

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to have a coordinated Operating Plan(s) which will have required the Reliability Coordinator to have reviewed the plans submitted by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, Part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, Part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here. The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, Parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	elements operated at less than 100 kV on BPS reliability.	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Proposed TOP-003-3, Requirement R1, part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-contingency operating conditions.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R13**: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.	**Proposed TOP-001-3, Requirement R14**: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, Part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		(Real-time Assessment may be provided through internal systems or through third-party services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	Model parameters are outside the scope of this project.
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for sub-100 kV data and monitoring as deemed necessary by the reliability entities. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. **Proposed IRO-002-4, Requirement R4**: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. **Proposed IRO-002-4, Requirement R4:** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	(1) Phase angle calculation tools are outside the scope of this project. (2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.	potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability. Training is outside the scope of this project.

Project 2014-03 - Revision of TOP/IRO Reliability Standards

Resolution of Issues and Directives

The following table contains a list of all FERC directives, industry issues, and Independent Expert Review Panel (IERP) recommendations associated with the standards being revised in Project 2014-03, with proposed resolutions.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	892. Consider commenters' suggestions as part of the standards development process. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.	The SDT has added measures for all requirements. The Regional Reliability Organization has been removed from the standards.
IRO-001-3	FERC Order 693	893. Consider commenters' suggestions as part of the standards development process. FirstEnergy	The SDT has considered the commenter's suggestions and believes that safety refers to any

Standard	Source	Language	Resolution
		suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.	type of safety including personal or equipment and that no additional wording is necessary. If a generator receives conflicting Operating Instructions, the generator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.
IRO-001-3	FERC Order 693	895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.	The SDT has considered the comments and believes that a Reliability Coordinator can direct a Qualifying Facility (registered as a GO or GOP) to act through the issuance of Operating Instructions. Therefore, no additional requirements are necessary.
IRO-001-3	FERC Order 693	896. Eliminate the references to the regional reliability organization as an applicable entity. Paragraph 896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 to substitute "Regional Entity" for "regional reliability organization" and reflect	The SDT has removed all references to the Regional Reliability Organization from the standards.

Standard	Source	Language	Resolution
		NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	
IRO-001-3	FERC Order 693	897. Consider adding measures and levels of non-compliance. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	The SDT has added measures and Violation Severity levels (VSLs) (which replaced levels of non-compliance) for each requirement.
IRO-001-3	FERC's December 20, 2007 and April 4, 2008 Orders	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance	The SDT has established requirements that apply to the Load-Serving Entity. **Proposed TOP-001-3, Requirement R3**: **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it

Standard	Source	Language	Resolution
		filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define “Non-Asset Owning LSEs” as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been	would violate safety, equipment, regulatory, or statutory requirements.

Standard	Source	Language	Resolution
		incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability First (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf)	

Standard	Source	Language	Resolution
		· NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.	
IRO-001-3	Fill in the Blank Team	Remove ", sub-region, or interregional coordinating group" from R1	Terms have been removed from the standard.
IRO-001-3	Version 0 Team	Inability to perform needs to be communicated	Clarity has been provided to address this issue throughout the various standards.
IRO-001	Version 0 Team	What is meant by 'interest of other entity'?	The SDT proposes to retire Requirement R9. All Reliability Coordinator Standard Requirements are developed so that the Reliability Coordinator shall act in the interest of reliability for the Reliability Coordinator Area and the Interconnection.
IRO-001-3	Fill in the Blank Team	Consider removing "Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market	The purpose statement has been revised accordingly.

Standard	Source	Language	Resolution
		participant over another." from the Purpose section of the standard.	Purpose: To establish the responsibility of Reliability Coordinators to act or direct other entities to act to prevent an Emergency.
IRO-001-3	NERC Audit Observation Team	All applicable registered functions shall comply with RC directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Inform the RC immediately of the inability to perform such directives. For audit purposes, what is acceptable evidence?	Measure M2 contains the provisions for suitable evidence. **Proposed IRO-001-4, Measure M2**: **M2**. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instruction, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator’s Operating Instruction. If no event has occurred, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service

Standard	Source	Language	Resolution
			Provider, or Distribution Provider may provide an attestation that an event has not occurred.
IRO-001-3	VRFs Team	R6 - Since the RC must be NERC certified, it stands to reason that anyone performing RC tasks should be certified. However, since the RC still retains the accountability for actions, and requirement 4 handles the agreements, this requirement is a medium risk.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
IRO-001-3	IERP	Requirement R1 content is incomplete. IERP recommended addressing 3 concepts as follows: RC has the authority to direct others to act. RC has the obligation to direct others to act to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.	The NERC Functional Model v5 spells out the authority of the Reliability Coordinator on page 30 under the description of the Reliability Coordinator functional entity. Proposed IRO-001-4, Requirement addresses the obligation of the Reliability Coordinator to direct others to act. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. The term ‘Reliability Directive’ has been replaced with the defined term ‘Operating Instruction.’

Standard	Source	Language	Resolution
		When directing others to act in accordance with this requirement, a RC must identify its directive as a "Reliability Directive". Consider consolidating with other authority-related standards and COM-003 in a single Authority standard as follows: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.	Proposed COM-002-4 determines the protocol for issuing Operating Instructions. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-001-3	IERP	IERP viewed Requirement R2 language as unclear and unable to be practically implemented. Questioned whether equipment requirements were a valid reason for not complying with RC direction. IERP proposed covering this requirement under a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.

Standard	Source	Language	Resolution
		safety, equipment, regulatory, or statutory requirements.	
IRO-001-3	IERP	IERP viewed content of Requirement R3 as incomplete by not requiring a reason for not complying with the RC's direction IERP recommended consolidating into a single Authority standard (see requirement above, which would replace both IRO-001 requirements R2 and R3)	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.
IRO-002-1	FERC Order 693	905 - Require a minimum set of tools that must be made available to the reliability coordinator. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.	The SDT revised the definition of Real-time Assessment and Operations Planning Analysis to require Transmission Operators and Reliability Coordinators to ensure that those entities will have the capabilities they need to fulfill their reliability responsibilities. The SDT has crafted the definitions to provide functionality and methodology as opposed to a specific tool set but strongly believes that the definitions and accompanying requirements to run the studies and take actions based on those studies goes beyond the directive and provides for a robust and reliable interconnected transmission system. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System

Standard	Source	Language	Resolution
			status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1:** **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R4:**

Standard	Source	Language	Resolution
			R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
IRO-002	Version 0 Team	R5 – define synchronized information system	The term is not used in the revised standards.
IRO-002	Version 0 Team	R7 – define 'adequate' tools and 'wide-area'	The terms are not used in the revised standards
IRO-002-1	Version 0 Team	Words such as 'easily understood' and 'particular emphasis' need to be tightened	The terms are not used in the revised standards
IRO-002-3	IERP	IERP viewed Requirement R1 as incomplete. RC also needs to approve any other work being done on the tools, hardware/software/telecom systems within the RC that could affect the quality and the content of the data coming into the control center. Also consider consolidating with Project 2009-02 Requirement R1 was proposed for consolidation under a new Authority standard: Authority R2 Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of	Proposed IRO-002-4, Requirement R2 addresses this issue. **Proposed IRO-002-4, Requirement R2**: **R2**. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.

Standard	Source	Language	Resolution
		its EMS, telecom and other hardware, and associated analysis tools.	
IRO-002-3	IERP	IERP viewed Requirement R2 as incomplete. Procedures need to address not only tools outages, but also tools maintenance or other inhibitors to quality performance of analysis tools. Also consider consolidating with Project 2009-02	The SDT added 'maintenance' approval to proposed IRO-002-3, Requirement R3. This includes all work being done on monitoring and analysis capabilities and not just those that will cause an outage. **Proposed IRO-002-4, Requirement R2**: **R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards.
IRO-003	Order 693	914. … we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area …	The term is not used in the revised standards. The proposed data specification concept allows for the Reliability Coordinator to ask for any reliability related data that it needs in order to fulfill its reliability tasks thus obviating the need for a specific criteria for determining critical facilities. And specific requirements for monitoring have been added for the Reliability Coordinator. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for

Standard	Source	Language	Resolution
			it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
IRO-004-1	Order 693	934. In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	Measures have been added to all requirements.
IRO-004-1	Order 693	935. …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency	The SDT has addressed this issue in proposed IRO-008-2 and TOP-002-4 as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. SOLs must be controlled according to the Operating Plan which is set up on time-based facility ratings (see SOL Exceedance White Paper for further details). IROLs are controlled to the IROL T_v which by definition is always less than 30 minutes. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to

Standard	Source	Language	Resolution
			assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and

Standard	Source	Language	Resolution
			Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed TOP-002-4, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
IRO-005	FERC Order 693	520. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive	The SDT addresses the need for Reliability Coordinator assessment and approval on a

Standard	Source	Language	Resolution
		included a Requirement for the reliability coordinator to assess and approve only those actions that have impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR.	requirement by requirement basis. For example, see proposed IRO-008-2, Requirements R3 and R6. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R5**: **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.
IRO-005-1	FERC Order 693	946. "Conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROLS, their causes, the date and time, the durations and	Completed and filed in Oct 2008

Standard	Source	Language	Resolution
		magnitudes in which actual operations exceeds IROLs to NERC.	
IRO-005-1	FERC Order 693	950- Provide further clarification that reliability coordinators and transmission operators direct control actions, not LSEs as part of the standard development process. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.	The SDT has proposed IRO-001-4, Requirement R1 to address the Commission's suggestion for clarification. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.
IRO-005-1	FERC Order 693	951-"Measures and levels of non-compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency, and causes of the violations and whether these occur during normal or contingency conditions. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO-005-1through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further	The SDT has added measures and VSLs (which replaced levels of non-compliance) for each requirement.

Standard	Source	Language	Resolution
		directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions.	
IRO-005-1	Fill in the Blank Team	R14 has regional reference	The term is not used in the revised standards.
IRO-005-1	Version 0 Team	R10, 11 & 12 – RA not empowered to do this	RA is no longer an applicable entity in the revised standards.
IRO-005-4	IERP	Requirement R1 is incomplete--needs to include Emergency. Requirement R1 reads: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. Also - there are gaps between the old std IRO-005-3 R2 to IRO-005-4: missing is: There is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required	The SDT replaced Adverse Reliability Impact with Emergency in all requirements. Emergency is a broader term. Proposed IRO-002-4, Requirement R3 addresses the issue of monitoring.

Standard	Source	Language	Resolution
		amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. (Minus strikethrough) FROM IRO-005-3 R9: Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows.	**Proposed IRO-002-4, Requirement R3**: **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area The SDT believes all appropriate items, including Special Protection System evaluation and awareness is addressed through the revised definitions of Real-time Assessment and Operations Planning Analysis. The data specification has been revised to explicitly address Special Protection Systems. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

Standard	Source	Language	Resolution
			(Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1. Part 1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
		From IRO-005-3 R10: In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	The SDT has addressed the issue of resolving differences in limits in proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R18**: **R18.** Each Transmission Operator and Balancing Authority shall always operate to the most limiting

Standard	Source	Language	Resolution
		Recommend consolidating with IRO-008 R3.	parameter in instances where there is a difference in SOLs. The SDT has consolidated requirements and standards as it believes appropriate.
IRO-005-4	IERP	The proposed standard creates a gap in outage coordination by proposing to retire IRO-005-3 R6. This could be resolved through an Authority standard as proposed by the IERP From IRO-005-3 R6: The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The SDT has proposed a new standard, IRO-017-1 Outage Coordination, to address this issue.
IRO-005-4	IERP	Requirement R2 should also include Emergency Requirement R2 reads: Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated.	The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency.

Standard	Source	Language	Resolution
		Note: there is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Recommend moving to IRO-008 and create an R4	
IRO-014-2	IERP	Gap in Requirement R1 - Need to identify RC's authority to direct another RC to take action - suggestion: create another Requirement, i.e., R6 (in proposed authority standard). Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT does not agree with this recommendation. A Reliability Coordinator does not direct another Reliability Coordinator. Proposed IRO-014-3 describes how to coordinate between Reliability Coordinators.
IRO-014-2	IERP	R2 is administrative and should be deleted	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R3 implements plan from R1; it should be combined with R1	The SDT believes that combining the requirements would create a complex requirement with multiple objectives that would be difficult to measure for compliance.
IRO-014-2	IERP	Requirement R4 is administrative and should be deleted.	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.

Standard	Source	Language	Resolution
IRO-014-2	IERP	R5 should require notification of “all IMPACTED RCs"; not "ALL"	The SDT has added ‘impacted’ to appropriate locations in the standards.
IRO-014-2	IERP	R6 should be consolidated with other standards that incorporate the concept of operating to the most conservative for reliability - IRO-009-1 R5 R6 reads: During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.	Approved IRO-009-1 only addresses IROLs. Proposed IRO-014-3 addresses all limits.
IRO-014-2	IERP	Requirement R7 should be retired. The reliability objective is covered under R6, and also supported by IRO-009-1 R5	The SDT believes that the two requirements are sufficiently distinct to warrant separateness. Requirement R6 speaks to actual operations. Requirement R7 speaks to having an established plan. The SDT believes that reliability is best served by having a plan to follow.
IRO-014-2	IERP	Requirement R8 should be retired. The reliability objective is covered under R6.	The SDT does not agree with this recommendation. Requirement R8 is a separate requirement.
IRO-016	VRF's Team	R1.2.1 & R2 – ambiguous	Requirement R2 was approved for retirement by FERC effective January 2014. Requirement R1, part 1.2.1 was incorporated in the set of requirements in proposed IRO-014-3, and ambiguous language has been deleted.
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.

Standard	Source	Language	Resolution
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This concern is addressed in proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	The term is not used in the revised standards
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been revised to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly

Standard	Source	Language	Resolution
			belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-001-2	IERP	Requirement R1 phrase "unless it violates requirements" is too permissive or there may be a better way to phrase it Consider consolidating TOP-001-2 Requirements R1 and R2 and all other standards requirements related Authority to into a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under [Authority standard R1] unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT believes that this is well understood language. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
TOP-001-2	IERP	The language “emergency assistance” in Requirement R4 is unclear. When and how must assistance be rendered, and what type?	The SDT revised the language for clarity and included the Balancing Authority.

Standard	Source	Language	Resolution
		BA's should be included as functional entity. Consider moving R4 to EOP standards (this is an "emergency" operating requirement)	**Proposed TOP-001-3, Requirement R7:** **R7**. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
TOP-001-2	IERP	Requirement R5 should also include notification of Emergencies (in addition to ARI), and should include Bas. R5 states: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.	The SDT added impacted Balancing Authorities. The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-2	IERP	R6 needs to include real time outages of telecom as well as planned outages.	The SDT added telecommunications to the requirement. **Proposed TOP-001-2, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of outages of telemetering and telecommunication equipment,

Standard	Source	Language	Resolution
		Requirement should be covered under COM-001	control equipment, monitoring and assessment capabilities, and associated communication channels between it and the affected entities. COM standards are not in scope for this project.
TOP-001-2	IERP	Requirement R8 does not cover all information needed for reliability. It should cover 1) SOLs within a TOP's/RC's footprint, 2) SOLs that are within one TOP's/RC's footprint that could affect another entity and 3) an SOL that spans into 2 TOP's/RC's footprints The requirement should also obligate the TOP to also inform impacted TOPs (The entity that could be impacted must tell the TOP that could impact them that it needs the info)	The SDT has addressed issue 1 in proposed TOP-001-3, Requirement R15. SOLs that cross boundaries are taken care of at the Reliability Coordinator level. **Proposed TOP-001-3, Requirement R15:** **R15**. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when a SOL has been exceeded.
TOP-002-3	Order 693	1597. Consider ISO-NE recommendation that the reference to “transmission service provider” in TOP-002-2 R12 be replaced by TOP and/or TO. Requirement R12 states: The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.	This requirement is now addressed by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **R6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or

Standard	Source	Language	Resolution
			increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3**: **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. Approved MOD-030-2, Requirement R2.4: Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
TOP-002-3	Order 693	1598. Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and Part 1.1:**

Standard	Source	Language	Resolution
			R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data as deemed necessary by the Transmission Operator.
TOP-002-3	Order 693	1600. Address critical energy infrastructure confidentiality as part of the routine standard development process	The data specification standards now contain provisions for addressing security of data. **Proposed IRO-010-2, Requirement R3, Part 3.3**:

Standard	Source	Language	Resolution
			R3. Part 3.3 A mutually agreeable security protocol. **Proposed TOP-003-3, Requirement R5, Part 5.3:** **R5. Part 5.3** A mutually agreeable security protocol.
TOP-002-3	Order 693	1601. …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages	SOLs are the responsibility of the Transmission Operator and IROLs are the responsibility of the Reliability Coordinator. This issue is addressed in proposed changes to the IRO standards. **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3**:

Standard	Source	Language	Resolution
			R3. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s).
TOP-002-3	Order 693	1606. Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	The SDT agrees and has addressed the issue in proposed TOP-002-3, Requirement R4, part 4.4: Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.
TOP-002-3	Order 693	1608. Require simulation contingencies to match what will actually happen in the field	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly. The definitions require Contingencies to match field conditions as they require evaluations against projected system conditions for Operational Planning Analysis and system conditions for Real-time Assessment. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational

Standard	Source	Language	Resolution
			Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
TOP-002-3	IERP	Requirement R1. TOP-008-1 R4 needs to be incorporated into TOP-002-3 requirement R1. Also - the definition of "Operational Planning Analysis" provides too much latitude in time. Recommend removing the parenthesis in the definition; the entity will make the determination and document (documentation is evidence) the applicability of what it uses for their next day study	The SDT revised the definition of Operating Planning Analysis and Requirement R1. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed TOP-002-3, Requirement R1: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
TOP-003-0	FERC Order 693	1620. …direct the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these type of issues. This new standard takes into account the recommendations from the Independent Expert Review Panel and SW Outage Report and brings all of the various outage coordination issues into one cohesive standard.
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of Project 2007-03 in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on

Standard	Source	Language	Resolution
			the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. In response to concerns raised by the IERP and the SW Outage Report, the SDT has developed proposed IRO-017-1 Outage Coordination. This standard requires the development of a coordinated outage process between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. If so desired, a Reliability Coordinator could include lead times in its process. In addition, proposed IRO-010-2 and TOP-003-2 dealing with data specifications could also cover this issue. The data specification must include any and all data required by the Reliability Coordinator, Transmission Operator and Balancing Authority. Planned outage data and timings could be included in such a data specification. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	Order 693	1622. Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these types of issues.

Standard	Source	Language	Resolution
TOP-003-0	Order 693	1624. Direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and Part 1.1**: **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including sub-100 kV data and external network

Standard	Source	Language	Resolution
			data as deemed necessary by the Transmission Operator.
TOP-003-2	IERP	Requirements R1 and R2 do not address level of accuracy required; see if this is provided elsewhere (i.e. project 2009-02) Consolidate R1 and R2 at minimum; at max consolidate with RC (IRO-010-1a R1)	Level of accuracy is one of the issues identified in the Real-Time Tools Best Practices Task Force Report. NERC is currently instituting a review of all of the recommendations in various reports, including the Real-time Tools Best Practices Task Force report, to see what actions should be taken, if any are still required, to address recommendations in the reports. The SDT does not want to consolidate the two responsibilities. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Consolidate R3 and R4 at minimum; at max consolidate with RC (IRO-010-1a R2)	The SDT does not want to consolidate the two requirements or the two standards. The SDT feels Requirements R3 and R4 are for different tasks. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Requirement R5 should be consolidated with IRO-010-1a R3	The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	The SDT believes that this issue has been addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment,

Standard	Source	Language	Resolution
			and the requirement for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances. The SDT has developed a white paper on the topic of SOL exceedance to explain the technical rationale behind this resolution. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and

Standard	Source	Language	Resolution
			identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R1**: **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14**: **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
TOP-004-1	Order 693	1637. …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Completed and filed in Oct 2008.

Standard	Source	Language	Resolution
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (… the Commission proposed to interpret “multiple outages” in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under … high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	The SDT feels that approved EOP-001-2.1b dealing with emergency operations planning covers the intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, approved FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.
TOP-004-1	Order 693	1639. Consider Santa Clara’s comment in the SDT process. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include	The data specification standards require that entities obtain all of the data that they need to perform their reliability functions. This would include frequency,

Standard	Source	Language	Resolution
		frequency monitoring in addition to the monitoring of voltage, real and reactive power flows	voltages, real and reactive power flows, and any other data that the entity needs. **Proposed IRO-010-2, Requirement R1**: **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	The SDT has clarified the issue. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL $T_{v.}$
TOP-005	Order 693	1648. ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1.	The SDT has added specific parts to the data specification standards as well as revising the definitions of Operational Planning Analysis and Real-time Assessment to address this issue. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The

Standard	Source	Language	Resolution
			evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**:

Standard	Source	Language	Resolution
			1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-005	Order 693	1650. Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process. FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. ISO-NE recommends that the reference to "purchasing-selling entity" should be replaced with LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-3. Requirement R4 has been superseded by proposed TOP-003-3 which does include the indicated entities and has deleted PSE. **Proposed TOP-003-3, Requirement R5**: **R5.**Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
TOP-005	Order 693	1651. … deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.	The SDT believes that confidentiality is a market issue and not a reliability issue and as such it does not belong in the Reliability Standards. However, security of information is a reliability concern and the SDT has addressed that issue through the addition of requirements for establishing security protocols in data exchanges. **Proposed TOP-003-3, Requirement R5, Part 5.3**: 5.3 A mutually agreeable security protocol. **Proposed IRO-010-2, Requirement R3, Part 3.3**: 3.3 A mutually agreeable security protocol.

Standard	Source	Language	Resolution
TOP-005	Order 693	1660. Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system	The SDT revised the definition of Real-time Assessment and Operations Planning Analysis to require Transmission Operators and Reliability Coordinators to ensure that those entities will have the capabilities they need to fulfill their reliability responsibilities. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be

Standard	Source	Language	Resolution
			provided through internal systems or through third-party services.)
TOP-006	Order 693	1665. Clarify the meaning of appropriate technical information concerning protective relays	That term is no longer used in the standards. To address concerns about the status of protection systems, the SDT has incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection

Standard	Source	Language	Resolution
			System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-006	Order 693	1664/1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	All requirements now have measures.
TOP-006	Order 693	1673. Direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan. NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as	Analysis is required in proposed TOP-002-3, Requirement R1 and in proposed TOP-001-3, Requirement R13. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1 and proposed TOP-001-3, Requirement R13 as shown in the revised definition of Operational Planning Analysis and Real-time Assessment. Additionally, approved NUC-001-2.1, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require

Standard	Source	Language	Resolution
		follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.	the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-3. Approved NUC-001-2, Requirements R3 & R8 cover the information flowing back to the nuclear plant operator. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

Standard	Source	Language	Resolution
			(Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved NUC-001-2.1, Requirement R3**: **R3**. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. **Approved NUC-001-2.1, Requirement R4.1**: 4.1 Incorporate the NPIRs into their operating analyses of the electric system. **Approved NUC-001-2.1, Requirement R8:** **R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric

Standard	Source	Language	Resolution
			system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.
VAR-001-1	Order 693 Transferred from Project 2013-04 Voltage and Reactive Control	1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	The SDT has clarified the issue of having the Reliability Coordinator provide oversight. The proposed requirement uses the term 'Facilities' which is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." Therefore, the requirement covers voltage and reactive resources. **Proposed IRO-002-4, Requirement R3**: **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
INT-006-1	Order 693	866. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability	An equally efficient and effective method of addressing the directive was approved by the Board

Standard	Source	Language	Resolution
	Transferred from Project 2008-12 Coordinate Interchange Standards	Standards development process that makes it applicable to reliability coordinators and transmission operators. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	and filed with FERC by Project 2008-12 SDT by including the term 'Interchange' in the definition of Operational Planning Analysis. This change has been retained by Project 2014-03. Proposed IRO-008-2, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. Then, in proposed IRO-008-2, Requirement R2, the Reliability Coordinator must develop a plan for addressing the problem. Similar requirements exist for the Transmission Operator in proposed TOP-002-3. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R1: **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:** **R3**. Each Reliability Coordinator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R3 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).

Standard	Source	Language	Resolution
			Proposed TOP-002-4, Requirement R2: **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R3:** **R3**. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC Operating Committee Response to NERC Standards Committee / RISC Triage of IERP Gaps

Updated August 2014

The NERC Operating Committee reviewed three perceived gaps, Outage Coordination, Governor Frequency Response, and Situational Awareness, as identified by the Independent Experts in their June 2013 report. As an important step in this review, the OC's Executive Committee met via WebEx with the Independent Experts to more thoroughly discuss and understand the thinking which led to these elements being cited as possible gaps. During the WebEx, the OCEC and the Independent Experts also reviewed all of the proposed requirements in the Independent Experts draft Authority matrix. The results of the OC's discussions, and the Project 2014-03 SDT's consideration within the revised TOP and IRO standards for two of the three perceived gaps (Outage Coordination and Situational Awareness) are presented below. The third gap identified by the Independent Experts, Governor Frequency Response, is outside the scope of Project 2014-03.

Outage Coordination

Draft requirements 3, 7, 8 and 9 of the Independent Experts draft Authority Standard focus on Outage Coordination. One concern recognized the fact that the Reliability Coordinators have a wide area view and broader situational awareness, allowing for early identification and resolution of conflicts. Therefore the RCs should have the most influence on outage coordination. Further concerns identify standards that are currently in flux, particularly those remanded standards in which requirements are being removed.

Operating Committee opinion

The Operating Committee concurs that Outage Coordination is an important grid reliability function. Outage coordination should originate from the TOPs and GOPs; with conflicts resolved by their respective RC. It makes sense for this process to begin with a set of previously approved scheduled long term outages with a sufficient time margin for results to be incorporated into seasonal operating studies. Further, the RC should retain the authority for final approval up to the time the asset is removed from service, as well as recall authority (if technically feasible and appropriate to recall) as needed to prevent or mitigate emergencies.

Longer term outage coordination is necessary for those assets that require long maintenance planning pursuant to the type of work required, such as turbine rebuilds, nuclear refueling, etc. This likely belongs in the scope of the Planning Coordinator (PC) for outages planned more than 12-months into the future. A Reliability Standard could be written that requires PCs to coordinate long term outages and which requires responsible entities (e.g., GOs, TOs) to request a time slot in which to perform whatever maintenance is required.

In either case, during the longer term planning horizon, or the Operations planning and real time operations time frame, each PC or RC should have an understanding of the impacts on neighboring PCs or RCs when those assets are planned to be out or are forced out, with notification/coordination requirements with these PCs or RCs.

SDT response:

To enhance reliability, the Project 2014-03 SDT has provided explicit requirement language to address the need for planned outage coordination at the Reliability Coordinator level. See proposed IRO-014-3, Requirement R1, part 1.4. The Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address overall outage coordination issues.

Proposed IRO-014-3, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Situational Awareness (EMS RTCA models)

In this gap the Independent Experts recommend the development of a standard that defines the requirements for EMS RTCA models or performance expectations of the models (Project 2009-02 – Real Time Monitoring and Analyses Capabilities).

Operating Committee opinion

The Operating Committee has a concern that this gap could be interpreted as recommending a "HOW" standard where specific tools would be required even for the smallest TOPs, as opposed to a "WHAT" standard that would allow for other ways to accomplish the objective. In conversations with the Independent Experts it became clear that proper situational awareness was the primary concern. The OC concurs that real time contingency analysis process (real time updated topology and telemetry) should be performed on each BES facility. This functionality could be performed by use of an RTCA application at the TO or RC level, or coverage by alternate means would be appropriate.

SDT response:

The Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13. In addition, the Project 2014-03 SDT has revised the definition of Real-time Assessment to allow for contracting needed services to accommodate concerns for smaller entities.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase

angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Remainder of the draft Authority Standard Requirements

Authority R1

Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.

Operating Committee opinion

The current IRO-001-1.1 and TOP-001-1a are expected to be retired and replaced by IRO-001-3. In either case, these standards contain the authority to act, but the requirement to act appears to be implicit. The OC agrees that the RC, TOP and BA should explicitly be required to act.

SDT response:

The Project 2014-03 SDT agrees and has adjusted the wording in the standards to address this issue.

Proposed IRO-001-4, Requirement R1: Each Reliability Coordinator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Reliability Coordinator Area.

Proposed TOP-001-3, Requirement R1: Each Transmission Operator shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area.

Proposed TOP-001-3, Requirement R2: Each Balancing Authority shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area.

Authority R2

Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.

Operating Committee opinion

The current IRO-002-2 provides for the RC to have control of its tools but does not include the TOP or BA. IRO-002-2 is expected to be retired and replaced by IRO-002-3, which clarifies that the system operators have the authority to approve outages of analysis tools (The OC suggests adding "under the direct control of their company"), but does not include TOPs or BAs. The OC concurs with the clarification in IRO-002-3, and the OC further agrees that TOPs and BAs should be included.

SDT response:

The Project 2014-03 has added proposed TOP-001-3, Requirements R16 and R17 to provide Transmission Operators and Balancing Authorities with capabilities similar to those of the Reliability Coordinator.

> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and Real-time Assessment capabilities.
>
> Proposed TOP-001-3, Requirement R17: Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.

Authority R4

RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.

Operating Committee opinion

During the OCEC/Independent Expert webex, the Independent Experts explained that the objective of this requirement is to mandate the posting of a letter in the control rooms granting authority to the system operators to carry out their required tasks. While the Operating Committee believes this is a good practice, it does not believe that it rises to the level of a Standards Requirement.

SDT response:

The Project 2014-03 SDT agrees with the position of the Operating Committee Executive Committee. A letter of authority located in the Control Room is an example of good utility practice. A change to the requirements is not warranted.

Authority R5

Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

In relation to R1 above this understanding seems implicit. However, in the interest of clarity the OC would support this requirement.

SDT response:

The Project 2014-03 SDT agrees.

Proposed TOP-001-3, Requirement R3: Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed TOP-001-3, Requirement R5: Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed IRO-001-4, Requirement R2: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Authority R6

Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

IRO-014-5, IRO-015-1 and IRO-016-1 describe inter RC procedures, Plans, notifications and coordination. These standards are expected to be retired and replaced by IRO-014-2 incorporating the pertinent requirements from the retiring standards. However, none of these standards explicitly include a requirement for one RC to comply with a directive from another RC.

The OC recognizes that coordination between RCs is vitally important. It is also recognized that an RC is the entity with the best understanding and situational awareness of its unique footprint. Therefore it is not believed to be beneficial for operational reliability for one RC to direct the actions of another RC. Rather, it is more appropriate to have this type of coordination documented within the requisite Joint Operating Agreements in which the appropriate assistance would be documented and understood in advance of such actions.

SDT response:

The Project 2014-03 SDT believes that proposed IRO-014-2 Requirements R3 – R6 already require Reliability Coordinators to coordinate and implement action plans even if the RC cannot agree that a problem exists or what the exact action plan is

Proposed IRO-014-2, Requirement R3: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

Proposed IRO-014-2, Requirement R4: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.

Proposed IRO-014-2, Requirement R5: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.

Proposed IRO-014-2, Requirement R6: Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Standards Authorization Request Form

When completed, email this form to:
Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	TPL-001-5		
Date Submitted:	TBD		
SAR Requester Information			
Name:	TBD		
Organization:	TBD		
Telephone:	TBD	E-mail:	TBD
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On October 17, 2013 the Commission issued its final ruling on TPL-001-4. In that ruling, FERC issued several directives that were to be addressed in the foreseeable future. In order to minimize the impact and burden on the industry caused by changes to address these directives, the resolution of other issues surrounding TPL-001-4 are proposed to be merged into one cohesive project. These issues include: addressing the directives of Order 786, resolution of the references to MOD standards due to revisions in that family of standards, addressing the comments and suggestions in the Independent Expert Review Report, possible integration of TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events, revision of requirement R8 to specifically include the Reliability Coordinator, and other miscellaneous issues that may have been discovered during the first few years of implementation of TPL-001-4.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of this SAR is to consolidate into one cohesive project any changes needed to TPL-001-4 due to FERC directives, independent reports, and operating experience gained during the first few years of implementation of TPL-001-4.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Successful implementation of the revised standard will assure that all issues surrounding TPL-001-4 are addressed in one cohesive project thus minimizing the impact and burden of subsequent implementation on the industry.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed Standard Drafting Team (SDT) shall modify NERC Reliability Standard TPL-001-4 to explicitly address the directives of Order 786 including any adjustments indicated from the review of footnote 12 use, resolution of the references to MOD standards due to revisions in that family of standards, addressing the comments and suggestions in the Independent Expert Review Report, possible integration of TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events, revision of requirement R8 to specifically include the Reliability Coordinator, and

SAR Information

other miscellaneous issues that may have been discovered during the first few years of implementation of TPL-001-4.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT shall:

1. Consider adjustments to footnote 12 threshold values due to the report on usage filed by NERC
2. Address directives from FERC Order 786
   a. Paragraph 40: "…we direct NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments."
   b. Paragraph 89: "… directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."
3. Consider any needed changes due to NERC's work on single points of failure in Protection Systems (paragraph 69 in FERC Order 786)
4. Consider the comments and suggestions in the Independent Expert Review Report
5. Consider the possible integration of TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events for the creation of one cohesive planning performance standard
6. Modify the references to MOD standards due to revisions in that family of standards
7. Revise Requirement R8 to specifically include the Reliability Coordinator
8. Revise as necessary due to implementation experience
9. Modify the measures and Violation Severity Levels as necessary to address modified requirements

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.

Reliability Functions		
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes

Reliability and Market Interface Principles	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-017-1	This standard will need to be revised once Requirement R8 is written as Requirement R3 of this standard will become redundant with revised Requirement R8.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in proposed IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor facilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2,

Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed TOP-002-4. All of the requirements were assigned a Medium VRF.

VRF for Proposed TOP-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in proposed TOP-003-3. Four of the five requirements were assigned a "Low" VRF: Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for Proposed TOP-003-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator and proposed TOP-003-3, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: approved IRO-010-1 for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R5, has only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-001-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-001-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking actions to preserve reliability.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to act, or direct others to act, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with Operating Instructions could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of the inability to follow an Operating Instruction could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-002-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to give operators the authority to approve planned outages and maintenance of telecommunication, monitoring and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-003-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have adequate monitoring systems with emphasis on cited criteria could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

There are six requirements in proposed IRO-008-2. Four of the six requirements were assigned a "Medium" VRF: Requirements R1, R2, R3, and R6. The other requirements were assigned a "High" VRF.

VRF for Proposed IRO-008-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an Operational Planning Analysis in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement and there are no comparable requirements to compare against. It is a coordination requirement in the operational planning timeframe so this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate an Operating Plan in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify entities of roles in Operating Plans in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure that a Real-time Assessment is performed at least once every 30 minutes could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. However, that requirement combines operations planning and Real-time. This requirement only applies to Real-time which in the belief of the SDT raises the VRF to High.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of roles in plans in the Real-time environment could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R15 which is assigned a Medium VRF. The requirements are similar in that proposed IRO-008-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3 is for Transmission Operators. Hence, this requirement is also assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of when exceedances have been mitigated will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-010-2. Two of the requirements, Requirements R1 and R2, are assigned "Low" VRFs. Requirement R3 is assigned a "Medium" VRF.

VRF for Proposed IRO-010-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R2.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the data requested does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed IRO-014-3. Four of the requirements, Requirements R4, R5, R6, and R7, were assigned a "High" VRF. Requirements R1 and R3 were assigned a "Medium" VRF. Requirement R2 was assigned a "Low" VRF.

VRF for Proposed IRO-014-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-014-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have and implement the plans and procedures, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Low VRF. The requirement is for maintenance of plans, processes, and procedures. Hence, the designation of a Low VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to maintain the plans, processes, and procedures is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other Reliability Coordinators, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.2) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R7 which has a High VRF assignment. The requirements are similar in that proposed TOP-001-3, Requirement R7 is for Transmission Operators and Balancing Authorities while proposed IRO-014-3, Requirement R9 is for Reliability Coordinators. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-017-1. All four of the requirements have been assigned a "Medium" VRF.

VRF for Proposed IRO-017-1, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a coordination process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Medium VRF. The requirement is for following the process described in proposed IRO-017-1, Requirement R1 which is assigned a Medium VRF. Hence, the designation of a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to follow the process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved TPL-001-4 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the assessments, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate solutions, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the "default" for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. Those VSLs tried to gradate the provision of data. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity supplies the data or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT has assigned these VSLs to be binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about complying with the Operating Instruction which has a binary Severe VSL in approved IRO-001-1.1. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about informing the Reliability Coordinator which has a single Moderate VSL in approved IRO-001-1.1. The SDT believes that such a failure should be classified as binary Severe under current guidelines.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R1. Those VSLs are gradated and the SDT has followed that pattern here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R8. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity has supplied the authority or it hasn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-003-2, Requirement R1. Those VSLs tried to gradate the degree of monitoring. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is doing the monitoring or it isn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R4. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is providing adequate monitoring facilities with the particular emphasis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-008-1, Requirement R1. Those VSLs tried to gradate the performance of the Operational Planning Analysis by the number of days in a month that it wasn't available. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity performs the analysis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no comparable requirement to compare against. The SDT believes that this is a binary situation where an entity performs the coordination activity or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs gradated the notification efforts. The SDT has followed a similar path and assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R2. Those VSLs gradated the performance of Real-time Assessments based on time increments. The SDT made a similar assignment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs partially gradated the notification elements. The SDT has followed a similar path but assigned a complete set of incremental VSLs here consistent with current accepted practice.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-001-3, Requirement R15. Those VSLs are set up as a binary Severe situation but that requirement only involves notifying one entity, the Reliability Coordinator. There are potentially many more entities involved with this requirement so the SDT has set up a gradated set of VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-014-1, Requirement R1. Those VSLs present an incremental approach and the SDT has continued that approach.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement with no comparable requirement to follow. There are a number of criteria cited for the requirement and this lends itself to an incremental approach for the VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs are presented in an incremental approach. Therefore, the SDT has assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.2. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs tried to gradate things but the only differential is whether evidence was provided or not – actions themselves are covered in Severe. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity develops a plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.1. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity implements the plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed TOP-001-3, Requirement R7. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to proposed IRO-005-3.1a, Requirement R6 which has gradated VSLs and the SFT has adopted that approach here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no similar requirement in the Reliability Standards. The responsible entity either follows the process or it doesn't. Attempting to increment the effort doesn't make sense. Therefore, this VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to approved TPL-001-4, Requirement R8. In that case, the VSLs are incremental. However, the responsible entities there are dealing with many other entities. In this case, the responsible entity is dealing only with Reliability Coordinators which makes an incremental approach unnecessary due to the much smaller number of involved entities. Therefore, the VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar in nature to proposed IRO-017-1, Requirement R1. The VSL has been assigned in a similar manner – binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Unofficial Comment Form

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8 p.m. EST **Friday, September 19, 2014.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

The project web page can be found at: http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx

Background Information - Project 2014-03 – Revisions to TOP/IRO Reliability Standards

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards.

On November 21, 2013, FERC issued a NOPR proposing to remand three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards and four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards. In the NOPR, FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."

In response, NERC filed a motion requesting that FERC defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process. That motion to defer action was granted on January 14, 2014.

The standard drafting team (SDT) formed to address those concerns made revisions to the TOP and IRO standards proposed to be remanded, along with several other IRO standards to provide consistency amongst the TOP and IRO standards, to address NOPR issues and recommendations made by the Independent Expert Review Panel, the IRO five-year review team, and the 2011 SW Outage Report. The initial draft standards were posted for an initial comment period and ballot through July 2, 2014.

This is the second posting of the standards. The SDT has made numerous changes in the second posting to the proposed standards and definitions in order to respond to industry comments raised in the first posting.

The SDT requests that commenters objectively evaluate the work of the SDT in responding to the issues raised in FERC's November 21, 2013 NOPR, along with the recommendations made by the Independent Expert Review Panel (IERP), the IRO FYRT, and the SW Outage Report. The drafting team has committed to address these issues and is not at liberty to question the issues in the FERC NOPR.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the changes made to respond to industry comments to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the changes made to respond to industry comments to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you agree with the changes made to respond to industry comments to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

4. Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

Comments:

5. Do you agree with the changes made to respond to industry comments to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

6. The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

7. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

8. Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

9. Do you agree with the changes made to respond to industry comments to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

Comments:

10. Do you have any comments on the changes made to respond to industry comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.

    Yes:

    No:

    Comments:

11. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements and to respond to industry comments. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

    Yes:

    No:

    Comments:

12. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

    Yes:

    No:

    Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-03 Revisions to TOP and IRO Standards

Additional Ballots Now Open through September 19, 2014

Now Available

Additional Ballots for three **TOP** and six **IRO Reliability Standards,** two definitions, and the implementation plan and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Friday, September 19, 2014.**

Background information, including a revised white paper and additional supporting documents for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards, definitions, implementation plan and associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326

Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Formal Comment Period Now Open through September 19, 2014

Now Available

A 45-day formal comment period for three **TOP** and six **IRO Reliability Standards,** two definitions, and the implementation plan is open through **8 p.m. Eastern on Friday, September 19, 2014.**

Background information, including a revised white paper and additional supporting documents for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 10-19, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Formal Comment Period Now Open through September 19, 2014

Now Available

A 45-day formal comment period for three **TOP** and six **IRO Reliability Standards,** two definitions, and the implementation plan is open through **8 p.m. Eastern on Friday, September 19, 2014.**

Background information, including a revised white paper and additional supporting documents for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 10-19, 2014.**

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Additional Ballot and Non-Binding Poll Results

Now Available

Additional ballots for nine **TOP/IRO Reliability Standards**, two definitions, and the implementation plan; and nine non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, September 19, 2014**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results	Non-Binding Poll Results
	Quorum /Approval	Quorum/Supportive Opinions
IRO-001-4	85.75% / 76.12%	85.34% / 74.01%
IRO-002-4	84.96% / 74.23%	85.04% / 69.69%
IRO-008-2	84.96% / 75.67%	85.34% / 69.39%
IRO-010-2	85.22% / 85.49%	85.63% / 83.78%
IRO-014-3	84.96% / 75.96%	85.63% / 78.61%
IRO-017-1	85.22% / 78.67%	86.22% / 74.19%
TOP-001-3	85.49% / 48.73%	86.51% / 53.45%
TOP-002-4	85.22% / 78.87%	86.51% / 73.30%
TOP-003-3	86.28% / 87.03%	86.51% / 79.30%
2 Definitions	83.11% / 93.34%	NA
Implementation Plan	83.91% / 90.13%	NA

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-03 TOP-001-3 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	324
Total Ballot Pool:	379
Quorum:	**85.49 % The Quorum has been reached**
Weighted Segment Vote:	48.73 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	39	0.481	42	0.519	0	7	17
2 - Segment 2	9	0.8	3	0.3	5	0.5	0	0	1
3 - Segment 3	83	1	38	0.567	29	0.433	1	5	10
4 - Segment 4	30	1	15	0.652	8	0.348	0	1	6
5 - Segment 5	82	1	27	0.466	31	0.534	0	11	13
6 - Segment 6	52	1	24	0.545	20	0.455	0	3	5
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.3	0	0	3	0.3	1	0	1
9 - Segment 9	3	0.3	1	0.1	2	0.2	0	0	0

10 - Segment 10	8	0.5	3	0.3	2	0.2	0	2	1
Totals	**379**	**7**	**150**	**3.411**	**143**	**3.589**	**2**	**29**	**55**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group: Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
				COMMENT

1	Georgia Transmission Corporation	Jason Snodgrass	Negative	RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC Comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz-American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
				COMMENT

1	Oncor Electric Delivery	Jen Fiegel	Negative	RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Abstain	COMMENT RECEIVED
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Robertson Patricia)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
				SUPPORTS THIRD PARTY COMMENTS -

2	ISO New England, Inc.	Matthew F Goldberg	Negative	(IRC SRC and NPCC RSC)
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Negative	COMMENT RECEIVED
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED - Eric Sutlief
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)

3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC-RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox for David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting MRO NSRF's comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	NO COMMENT RECEIVED - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)

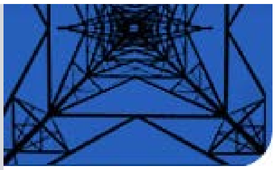
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz (FRCC))
4	South Mississippi Electric Power Association	Steve McElhaney		

4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments from HQT)
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT

				RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox\David Austin NIPSCO)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYISO)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comment)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox/DAvid Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review

				Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments)
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson (BCH))
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	NO COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
9	New York State Public Service Commission	Diane J Barney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	



10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 TOP-002-4 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	323
Total Ballot Pool:	379
Quorum:	**85.22 % The Quorum has been reached**
Weighted Segment Vote:	78.87 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	64	0.78	18	0.22	0	6	17
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	83	1	46	0.697	20	0.303	0	7	10
4 - Segment 4	30	1	17	0.895	2	0.105	0	5	6
5 - Segment 5	82	1	39	0.722	15	0.278	0	14	14
6 - Segment 6	52	1	32	0.727	12	0.273	0	3	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.5	5	0.5	0	0	0	2	1
Totals	**379**	**7**	**215**	**5.521**	**70**	**1.479**	**0**	**38**	**56**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
				SUPPORTS

1	KAMO Electric Cooperative	Walter Kenyon	Negative	THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lincoln electric's comments)
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	

1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox for

				David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		

4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		

5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox\David Austin NIPSCO)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - Southern Company - (SERC OC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		

5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox/DAvid Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - GSOC - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2014-03 TOP-003-3 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	327
Total Ballot Pool:	379
Quorum:	**86.28 % The Quorum has been reached**
Weighted Segment Vote:	87.03 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	66	0.795	17	0.205	0	6	16
2 - Segment 2	9	0.7	6	0.6	1	0.1	0	1	1
3 - Segment 3	83	1	59	0.881	8	0.119	0	7	9
4 - Segment 4	30	1	20	0.952	1	0.048	0	3	6
5 - Segment 5	82	1	47	0.797	12	0.203	0	10	13
6 - Segment 6	52	1	39	0.867	6	0.133	0	3	4
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	1	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**379**	**7**	**249**	**6.092**	**46**	**0.908**	**1**	**31**	**52**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED - Mike Hill
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	

1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)

5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	NO COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-001-4 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	325
Total Ballot Pool:	379
Quorum:	**85.75 % The Quorum has been reached**
Weighted Segment Vote:	76.12 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	57	0.722	22	0.278	0	10	16
2 - Segment 2	9	0.8	4	0.4	4	0.4	0	0	1
3 - Segment 3	83	1	53	0.791	14	0.209	0	7	9
4 - Segment 4	30	1	18	0.818	4	0.182	0	1	7
5 - Segment 5	82	1	41	0.732	15	0.268	0	12	14
6 - Segment 6	52	1	36	0.818	8	0.182	0	4	4
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**7.2**	**221**	**5.481**	**69**	**1.719**	**0**	**35**	**54**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	COMMENT RECEIVED
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Abstain	COMMENT RECEIVED
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Robertson Patricia)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	

3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPS Energy)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
				SUPPORTS THIRD

3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz (FRCC))
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments from HQT)
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	

6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson (BCH))
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		

10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-002-4 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	322
Total Ballot Pool:	379
Quorum:	**84.96 % The Quorum has been reached**
Weighted Segment Vote:	74.23 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	44	0.638	25	0.362	0	19	17
2 - Segment 2	9	0.7	4	0.4	3	0.3	0	1	1
3 - Segment 3	83	1	40	0.714	16	0.286	0	17	10
4 - Segment 4	30	1	14	0.875	2	0.125	0	8	6
5 - Segment 5	82	1	33	0.717	13	0.283	0	21	15
6 - Segment 6	52	1	28	0.778	8	0.222	0	11	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.2	1	0.1	1	0.1	0	1	0

10 - Segment 10	8	0.5	5	0.5	0	0	0	2	1
Totals	**379**	**6.9**	**173**	**5.122**	**69**	**1.778**	**0**	**80**	**57**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
				SUPPORTS THIRD PARTY COMMENTS -

1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	(Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see NPCC comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	

1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Negative	COMMENT RECEIVED
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	

3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC-RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	

3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz (FRCC))
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	

4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Affirmative	
				SUPPORTS THIRD

5	New York Power Authority	Wayne Sipperly	Negative	PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
				SUPPORTS THIRD

6	Duke Energy	Greg Cecil	Negative	PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else’s comments” and add “SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-008-2 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	322
Total Ballot Pool:	379
Quorum:	**84.96 % The Quorum has been reached**
Weighted Segment Vote:	75.67 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	52	0.776	15	0.224	0	21	17
2 - Segment 2	9	0.7	4	0.4	3	0.3	0	1	1
3 - Segment 3	83	1	38	0.691	17	0.309	0	18	10
4 - Segment 4	30	1	14	0.875	2	0.125	0	8	6
5 - Segment 5	82	1	34	0.739	12	0.261	0	22	14
6 - Segment 6	52	1	26	0.765	8	0.235	0	12	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.1	1	0.1	0	0	0	2	0

10 - Segment 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals	**379**	**6.8**	**177**	**5.146**	**59**	**1.654**	**0**	**86**	**57**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company	Michael Moltane	Abstain	

	Holdings Corp			
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Negative	COMMENT RECEIVED
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED - Eric Sutlief
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
				SUPPORTS THIRD PARTY

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	

4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
				SUPPORTS THIRD PARTY

5	Nebraska Public Power District	Don Schmit	Negative	COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - GSOC - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	

8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Abstain	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Ballot Results	
Ballot Name:	Project 2014-03 IRO-010-2 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	323
Total Ballot Pool:	379
Quorum:	**85.22 % The Quorum has been reached**
Weighted Segment Vote:	85.49 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	65	0.813	15	0.188	0	8	17
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	83	1	59	0.894	7	0.106	0	7	10
4 - Segment 4	30	1	20	0.952	1	0.048	0	3	6
5 - Segment 5	82	1	47	0.825	10	0.175	0	11	14
6 - Segment 6	52	1	39	0.886	5	0.114	0	3	5
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	1	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**7.1**	**247**	**6.07**	**42**	**1.031**	**1**	**33**	**56**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	

5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	

5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson (BCH))
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	NO COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2014-03 IRO-014-3 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	322
Total Ballot Pool:	379
Quorum:	84.96 % The Quorum has been reached
Weighted Segment Vote:	75.69 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	60	0.857	10	0.143	0	18	17
2 - Segment 2	9	0.7	3	0.3	4	0.4	0	1	1
3 - Segment 3	83	1	51	0.895	6	0.105	0	16	10
4 - Segment 4	30	1	14	0.875	2	0.125	0	7	7
5 - Segment 5	82	1	39	0.83	8	0.17	0	21	14
6 - Segment 6	52	1	32	0.865	5	0.135	0	10	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	1	0.1	3	0.3	0	0	1
9 - Segment 9	3	0.2	0	0	2	0.2	0	1	0

10 - Segment 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals	**379**	**6.9**	**205**	**5.222**	**41**	**1.678**	**0**	**76**	**57**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	

1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see npcc comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	

1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Negative	COMMENT RECEIVED
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	

3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	

4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	

5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz

				of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYISO)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - GSOC - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	

6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Debra R Warner		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and ISO-NE)
9	New York State Public Service Commission	Diane J Barney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2014-03 IRO-017-1 June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	323
Total Ballot Pool:	379
Quorum:	85.22 % The Quorum has been reached
Weighted Segment Vote:	78.67 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	58	0.725	22	0.275	0	8	17
2 - Segment 2	9	0.8	5	0.5	3	0.3	0	0	1
3 - Segment 3	83	1	46	0.708	19	0.292	1	7	10
4 - Segment 4	30	1	17	0.944	1	0.056	0	6	6
5 - Segment 5	82	1	39	0.709	16	0.291	0	13	14
6 - Segment 6	52	1	31	0.721	12	0.279	0	4	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.5	5	0.5	0	0	0	2	1
Totals	**379**	**7**	**208**	**5.507**	**73**	**1.493**	**1**	**41**	**56**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	

1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lincoln Electric's comments)
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED

1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Amy Casusceli, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Robertson Patricia)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Negative	COMMENT RECEIVED
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson, BC Hydro)
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas

				Standifur)
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP)

				comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	NO COMMENT RECEIVED - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy's)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	

4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	

5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		

5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - GSOC - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson (BCH))
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Negative	COMMENT RECEIVED
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2014-03 Definitions June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	315
Total Ballot Pool:	379
Quorum:	83.11 % The Quorum has been reached
Weighted Segment Vote:	93.34 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	66	0.892	8	0.108	0	12	19
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	1	2
3 - Segment 3	83	1	57	0.95	3	0.05	1	12	10
4 - Segment 4	30	1	17	1	0	0	0	6	7
5 - Segment 5	82	1	47	0.887	6	0.113	0	12	17
6 - Segment 6	52	1	37	0.925	3	0.075	0	6	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.4	4	0.4	0	0	0	3	1
Totals	**379**	**6.7**	**240**	**6.254**	**21**	**0.446**	**1**	**53**	**64**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	

1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan	Abstain	

		Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Rob Fox for David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	NO COMMENT RECEIVED - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		

4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox\David

				Austin NIPSCO)
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
				SUPPORTS THIRD PARTY

6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENTS - (Rob Fox/DAvid Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Ballot Results	
Ballot Name:	Project 2014-03 TOP/IRO Implementation Plan June 2014_sc_1
Ballot Period:	9/10/2014 - 9/19/2014
Ballot Type:	Successive
Total # Votes:	318
Total Ballot Pool:	379
Quorum:	**83.91 % The Quorum has been reached**
Weighted Segment Vote:	90.13 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	62	0.849	11	0.151	0	15	17
2 - Segment 2	9	0.5	4	0.4	1	0.1	0	2	2
3 - Segment 3	83	1	53	0.898	6	0.102	0	14	10
4 - Segment 4	30	1	18	1	0	0	0	5	7
5 - Segment 5	82	1	42	0.824	9	0.176	0	15	16
6 - Segment 6	52	1	33	0.868	5	0.132	0	8	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.4	4	0.4	0	0	0	3	1
Totals	**379**	**6.7**	**224**	**6.039**	**32**	**0.661**	**0**	**62**	**61**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
				SUPPORTS THIRD

3	Florida Power Corporation	Lee Schuster	Negative	PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Abstain	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch,	Margaret Powell		

	L.L.C.			
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	

5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	

5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-001-3
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	295
Total Ballot Pool:	341
Summary Results:	86.51% of those who registered to participate provided an opinion or an abstention; 53.45% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see NPCC comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)

1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	

3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED - Eric Sutlief
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC-RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED

3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox for David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting MRO NSRF's comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	

3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz of the)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	

5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments from HQT)
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox\David Austin NIPSCO)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)

5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	

6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYISO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox/DAvid Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of the FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and ISO-NE)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	

10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-002-4
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	295
Total Ballot Pool:	341
Summary Results:	86.51% of those who registered to participate provided an opinion or an abstention; 73.30% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	

1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	

1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Tallahassee	Bill R Fowler	Affirmative	

3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	

3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox for David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		

4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)

5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob

				Fox\David Austin NIPSCO)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	

6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox/DAvid Austin NIPSCO)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	

6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-003-3
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	295
Total Ballot Pool:	341
Summary Results:	86.51% of those who registered to participate provided an opinion or an abstention; 79.30% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	NO COMMENT RECEIVED
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED - Mike Hill
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	

1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	

3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPS Energy)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	

4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		

5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		

5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumppert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	

6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		

7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03_IRO-001-4
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	291
Total Ballot Pool:	341
Summary Results:	85.34% of those who registered to participate provided an opinion or an abstention; 74.01% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group: Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)

1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		

3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	

3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz of the)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	

5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments from HQT)
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	

5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	

5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)

6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		

10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-002-4
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	290
Total Ballot Pool:	341
Summary Results:	85.04% of those who registered to participate provided an opinion or an abstention; 69.69% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NPCC comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services) submitted by John Libertz of the FRCC)
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	

3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC-RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		

3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments by John Libertz)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		

3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee (Member Services) submitted by John Libertz of the)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	

5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		

5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of the FRCC Operating Committee(Member Services) submitted by John Libertz of FRCC)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	

5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	

6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-008-2
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	291
Total Ballot Pool:	341
Summary Results:	85.34% of those who registered to participate provided an opinion or an abstention; 69.39% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		

1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson		

3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED - Eric Sutlief
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	

3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera	Abstain	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian		

4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		

5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eric Sutlief)
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	

5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	

6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-010-2
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	292
Total Ballot Pool:	341
Summary Results:	85.63% of those who registered to participate provided an opinion or an abstention; 83.78% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aces)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	

1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		

3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	

3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED

4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	

5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	

5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	

6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-014-3
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	292
Total Ballot Pool:	341
Summary Results:	85.63% of those who registered to participate provided an opinion or an abstention; 78.61% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National

				Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments.)
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SPP Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see npcc comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	

1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC and NPCC RSC)
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	

3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)

3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	

5	Con Edison Company of New York	Brian O'Boyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO and NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)

5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYISO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else’s comments” and add “SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	

6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and ISO-NE)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-017-1
Poll Period:	9/10/2014 - 9/19/2014
Total # Opinions:	294
Total Ballot Pool:	341
Summary Results:	86.22% of those who registered to participate provided an opinion or an abstention; 74.19% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (aeci)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	

NERC

1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		

3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Pressler, CPSEnergy)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)

3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (RoLynda Shumpert)
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED

4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		

NERC

5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	

5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rolynda Shumphert)
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Libertz of FRCC)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (support someone else's comments" and add "SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kieth Morisette)

6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (59 Responses)
Name (40 Responses)
Organization (40 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (50 Responses)
Question 1 Comments (59 Responses)
Question 2 (45 Responses)
Question 2 Comments (59 Responses)
Question 3 (45 Responses)
Question 3 Comments (59 Responses)
Question 4 (51 Responses)
Question 4 Comments (59 Responses)
Question 5 (43 Responses)
Question 5 Comments (59 Responses)
Question 6 (51 Responses)
Question 6 Comments (59 Responses)
Question 7 (56 Responses)
Question 7 Comments (59 Responses)
Question 8 (51 Responses)
Question 8 Comments (59 Responses)
Question 9 (51 Responses)
Question 9 Comments (59 Responses)
Question 10 (45 Responses)
Question 10 Comments (59 Responses)
Question 11 (33 Responses)
Question 11 Comments (59 Responses)
Question 12 (52 Responses)
Question 12 Comments (59 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
The Purpose of IRO-004-4 is: “To establish the responsibility of Reliability Coordinators to act or direct others to act.” The Functional Model states that Reliability Coordinators interact with Transmission Service Providers, and Transmission Service Providers interact with Reliability Coordinators. Why is the TSP being removed from the Applicability and the Requirements? The contents of the Rationale boxes need to be reviewed and revised. For example, The Rationale under Applicability mentions Purchasing-Selling Entity and Load-Serving Entity being deleted from IRO-001-1.1. The Rationale for Requirements R2 and R3

mentions the retirement of IRO-004-2. The Rationale for IRO-001-4 should deal with IRO-001-4. The Drafting Team should consider the removal of the Rationale Box for R2 and R3. Suggest that the Drafting Team consider replacing the word “ensure” where used in the Requirements and Measures and VSL Table with the word “maintain”. Because Transmission Service Provider is being removed from the Applicability of the standard, Transmission Service Provider needs to be removed from the body of the standard. For example, the Quality Review did not catch its use in the Data Retention section.
No
The contents of the Rationale boxes must be reviewed with respect to their applicability to IRO-002-4. The Drafting Team should clarify and coordinate the requirements between voice and data equipment requirements and the associated COM-001 and IRO-002-4. The SDT should clarify the COM-001 is restricted to voice communications and the IRO-002-4 R1 is intended to address data. It is also not clear that IRO-002-4 R2 is limited to voice communication and/or data. A wording change for R2 to be considered: Each Reliability coordinator shall have the authority to approve planned outages and maintenance of its telecommunication and data exchange capabilities (as referenced in R1). Requirement R3 has had the word “telecommunication” added to it. Should also add the word telemetering to make the requirement read “…telecommunication and telemetering…”. Then use of telecommunication and telemetering should be made consistent throughout the document. In Requirement R4 delete the comma between “…Special Protection Systems, and sub-100kV…” to make it read “…Special Protection Systems and sub-100kV…”. This makes it clear that both Special Protection Systems and sub-100kV facilities shall be monitored.
No
“Ensure” or “ensured” should not be used in the standard. The contents of the Rationale boxes must be reviewed to ensure they are consistent with their associated Requirements. For example, the Rationale for Requirements R5 and R6 refers to the use of the word “impacted”. Impacted is not used in Requirement R5. The contents of the Rationale for R1, and R3 and R4 should be expanded to provide a short background statement for the Rationale. The wording of requirements should be made consistent. Why is Requirement R7 being deleted?
Yes
No
The Rationale for Requirement R1 explains what review changes were made, and do not address the contents of the Requirements. The Rationale for Requirement R1 should be removed. Measure M1 reflects Part 1.5 not being removed. Why is Part 1.5 being removed? A RC should have the detailed authority. What Requirements does the Rationale on page 7 refer to? The replacement of the word “other” with “adjacent” may leave a reliability gap. Because the words “may impact” already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word “other” into R1. The Drafting Team

should review the use of the phrase “Wide Area” in IRO-008-2 (and other IRO standards) and the phrase “Reliability Coordinator Area” in IRO-014-3. If these phrases are synonymous, then use of one or the other should be decided upon. Regarding the Retention Period, there are no data retention periods for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors. Suggest restoring the standard to its original wording.
No
“Operations Planning” in the Purpose is not defined in the NERC glossary and should not be capitalized. Regarding the Rationale and Time Horizon boxes on page 5: The words in the Rationale is appropriate for a guideline or announcement. It does not belong in a Rationale box. Neither “Time Horizon” nor “Operations Planning Time Horizon” is in the NERC Glossary and should not be capitalized. If those terms are to be considered for inclusion in the NERC Glossary, then they should be included on the Definitions of Terms Used in Standard. The R1 wording “…within its Reliability Coordinator Area” should be removed. Part 1.4 refers to “…other Reliability Coordinators”. The box “Note on part 1.5” does not belong in the standard. It is a comment response. “Near-Term Transmission Planning Horizon” is defined as “The transmission planning period that covers Year One through five.” The Rationale for Requirement R4 should be revised to just address the “why”, and justification for R4. During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT’s response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, sub-Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support sub-Part 1.1.2 as written, and suggest the Drafting Team to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
No
Regarding Requirements R1 and R2, “ensure” should not be used as mentioned in previous comments. This must be honored THROUGHOUT the standard. For this particular requirement, consider using the word “maintain” or “restore” instead. Throughout the standard, consider replacing “address” with “maintain”. The Time Horizon should not include Operations Planning, or Same-Day Operations. The phrase, ‘within its TOP/BA Area’ should not be removed. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. Regarding Requirement R3, Time Horizons should not include Operations Planning, or Same-Day Operations. Regarding ALL the standard’s requirements, where Operating Instruction is used, the Time Horizon category must be reviewed. In Requirement R7, the “e” in emergency must be capitalized.

“Comparable” should be added before “assistance”. In R7, the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it from the previous requirements. To address the Drafting Team response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. The previous language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency. In Requirement R9, strike the words “interconnected NERC registered” to be consistent with TOP-002-4 Requirement R3. The language in Requirement R16 should be made consistent with the language in Requirement R9. There should be consistent language used in requirements R9, R16, and R17. During the last posting, a concern was expressed over the ambiguity in R9 as the words “between the affected entities” can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities. Regarding Requirement R10, a Transmission Operator cannot be held responsible for monitoring ANY facilities in neighboring Transmission Operator areas. A Transmission Operator can only rely on what information is provided by a neighboring Transmission Operator. The new requirement R19 addresses the data exchange capabilities needed. The Drafting Team should consider removing R10. If Requirement R10 is to remain, then if a sub-100 kV facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP’s entire area when in reality a subset of facilities may be all that is required. One suggested rephrasing is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area… Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. The Drafting Team should consider removing “ensure” or its replacement word from Requirement R11. Refer to standard PRC-001-1.1. Requirement R13 should be reworded to: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The “s” in system should be capitalized in Requirement R15. The word “own” should not be deleted

from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. “Always” should be removed from Requirement R18. In Requirement R19 “(Balancing Authority Area)” is not needed and should be removed. In Requirement R20 remove “(Balancing Authority Area)” and “Transmission Operator Area”. What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility several Transmission Operator Areas away from a Transmission Operator Area impacts that Transmission Operator Area.
No
The proposed definition for Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a redline of what is in the NERC Glossary. The Rationale for Requirement R1 can be removed, and be placed in a guideline or support document. The Rationale for Requirement R3, and Rationale for Requirements R4 and R5 can be removed. It belongs in Consideration of Comments. The Rationale for Requirements R6 and R7 can be removed, and be placed in a guideline or support document.
No
The proposed definitions for Real-time Assessment and Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a red line of what is in the NERC Glossary. Additional information should be added to the Rationale for Requirement R5 for justification and background.
Yes
In the White Paper System Operating Limit Definition and Exceedance Clarification, delete the phrase “unit/intra-area instability,” from the Transient Stability Limits description. Individual unit instability is not being looked at; operations are to prevent system instability. During the last posting, the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded was commented on. The Drafting Team’s response indicates that “it has revised the whitepaper to include “as necessary and appropriate”. However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that “All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.” We speculate that the insertion of “as necessary and appropriate” to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, “However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating).” We urge the SDT to reassess whether or not the

“as necessary and appropriate” should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.
Yes
Yes
Because of the similarities in Purposes, Applicabilities, and Requirements of standards within the group that is posted, combining requirements with the intent on reducing the number of standards should be considered. During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT’s response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid. In other word, there does not exist any “proven reliable power system limits” as stated in R4 of TOP-002-4. While the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon may seem appropriate, the concept itself (and being in a “white paper” status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state. If R4 in TOP-004-2 is retired, it leaves a potential reliability gap. The white paper does not mandate the proper and necessary action to “restore operations to respect proven reliable power system limits within 30 minutes” when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. A proper Quality Review of the postings would have eliminated the necessity of submitting many of the above comments.
Group
FRCC Compliance
Scott Knewasser
NA
NA
NA
NA
NA

NA
NA
NA
NA
NA
NA
Yes
1. IRO-001-4 R1, TOP-001-3 R1 & R3: The phrase "… to ensure the reliability of its RC/TOP/BA Area." is not measurable. The requirements should be stated so that the stated reliability is objectively measurable. For example, "… to ensure all Facilities within the RC/TOP/BA Area remain within SOLs and IROLs." Otherwise, the requirements are too vague as to when the RC/TOP/BA would be required to act, or whether the action taken was sufficient to ensure reliability. 2. TOP-002-4 R1: The definition of Operational Planning Analysis does not specify what "potential (post-Contingency) conditions" are to be evaluated, and is therefore not measurable. Either the requirement or the definition should be revised to clarify and add measurability as to which contingencies are required to be included in the analysis. 3. TOP-002-4 R4 (4.2): The phrase "…for the next-day that addresses: Interchange scheduling" is too vague and not measurable. The requirement should be stated so as to be objectively measurable. For example, "… for the next-day that addresses: Expected Interchange scheduling". 4. TOP-002-4 R4 (4.4): The phrase "… for the next-day that addresses: Capacity and energy reserve requirements …" is not measurable. Applicable reserve requirements should be clearly provided to provide measurability as to whether the Operating Plan addressed them. For example, "… for the next-day that addresses: Capacity and energy reserve requirements (at a minimum N-1 Contingency planning) …"
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
No
AECI agrees with SPP comments regarding R1-R3: R1 – We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Reliability Coordinator takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R1 specifically to those entities identified in Requirements R2 and R3.We recommend the following rewrite: 'Each Reliability Coordinator shall act, or direct others as identified in Requirements R2 and R3 to act, by issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area. ' Rationale Box for Requirements R2 & R3 – The Rationale Box for Requirements R2 and R3 does not match the language in the requirements. There is no mention of the Transmission Service Provider in the requirements. It only appears in Measures M2 and M3. The IRO Five Year Review Team had recommended adding Transmission Service Provider to Requirements R2 and R3 to allow

the retirement of IRO-004-2. With the removal of the Transmission Service Provider in Requirements R2 and R3, can the retirement of IRO-004-2 move forward?
No
AECI agrees with SERC comments regarding R2: The OC Review Group suggests adding the word ‘its’ between ‘with’ and ‘Balancing Authorities’ to provide clarity. Suggested Wording: “R2: Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.”
No
AECI agrees with SERC comments regarding R8: In R8, the OC Review Group suggests removing the words ‘prevented or’ because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs. Suggested Wording: “R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated.”
Yes
Yes
No
AECI agrees with SERC and SPP comments regarding R4: In R4, the OC Review Group suggests adding “on the BES” before “with planned outages” to clearly define the BES as the subject portion of the system. Suggested Wording: “R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.”
No
AECI agrees with SERC and SPP comments regarding R1 and R2: The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI. Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining

compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: “Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area.” AECI agrees with SPP comments regarding R10: R10 – We have concerns with the existing language in Requirement R10 which when applied in the real-world of today’s audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn’t model enough of the neighboring TOP’s Area? Isn’t this really the function of the RC and aren’t we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: Each Transmission Operator shall monitor the following to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. 10.1 Facilities within its TOP Area 10.2 Status of Special Protection Systems identified as applicable by the Transmission Operator 10.3 Sub-100 kV facilities identified as applicable by the Transmission Operator, and 10.4 Facilities within neighboring Transmission Operator Areas identified as applicable by the Transmission Operator
No
AECI agrees with SERC comments regarding R1: In R1, the OC Review Group suggests adding the word “identified” before “SOLs” to clarify transmission operators are operating to the identified SOLs. Suggested Wording: “R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its identified System Operating Limits (SOLs).”
Yes
No
No
TOP-001-3 R2 Severe VSL – Remove “within its Transmission Operator Area” to maintain consistency with current R2. TOP-001-3 R7 Severe VSL – Replace “if requested” with “when requested” and “when the requesting” with “and the requested” to avoid issues with predicting future performance, and correct possession of the requested entity. Suggested language: “The Transmission Operator did not provide assistance to other Transmission Operators, when requested and able and the requested entity had implemented its emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.”
No
Group

FRCC Operating Committee (Member Services)
John A. Libertz
The groups represented by the FRCC Operating Committee support IRO-001-4 revisions in principle, however we seek clarification on the potential interpretations of the term “Operating Instructions” and the potential administrative impact to normal and emergency BES operations needed to demonstrate compliance as stipulated in the Measures.
Yes
However, R5 requires “synchronized information systems”. The FRCC Operating Committee seeks clarification from the drafting team on what constitutes a “synchronized information system”. Consider replacing the word “synchronized” with “coordinated.”
Yes
Yes
Yes
Yes
Yes
The FRCC Operating Committee supports a majority of these proposed requirements. However, the OC does not support the language in new requirement R9 and finds that the mapping from current requirement (TOP-003-1 R3) is incomplete and needs to be addressed by the standard drafting team. The language in the existing TOP-003-1 R3 is more precise and should remain as is. If the SDT is attempting to address the comments from the SW Outage Report Recommendations “TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities,” they should create a separate requirement to reflect the notification for loss of Real-time Assessment capabilities. At a minimum, the requirement should state “telemetering and control equipment”, rather than “telemetering equipment, control equipment”. This will add clarification to the type of equipment being addressed in the requirement. In addition, the word “planned” from M9 was not removed as noted in SDT responses. We also recommend removing the words “interconnected NERC Registered”. The word “impacted” reflects who should be notified. The current mapping of existing TOP-003-1 R3 to TOP-001-3 R9 does not accurately reflect the original intent of TOP-003-1 R3. R19 and R20 have some inconsistencies with referencing TOPs and BAs.
Yes
Yes
Yes

We suggest adding the following clarification to page 2 of the white paper: • Remove the terms “Normal (continuous)” from the Pre-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. • Remove the terms “Emergency (short term)” from the Post-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. We also suggest that the paper be reviewed for consistency when using the terms “pre-contingency” and “post-contingency”. Interchanging the use and context causes confusion – i.e. Change the column headers in Table 1, “Pre-Contingency Loading” to “Pre-Contingency Mitigation” and change “Post-Contingency Loading” to “Post Contingency Mitigation”. Another example would be to use “Real-Time flow” instead of “Pre-Contingency Flow”. Also in Table 1, under the ‘Emergency (4hr)” row – “Post Contingency Loading” column change “all” to “available”.
Yes
The comments provided herein are consensus comments of the FRCC Operating Committee entity representatives. Our responses to the above questions in no way intends to convey how individual FRCC OC member entities will vote on the standards being proposed. Thank you for your efforts.
Individual
Jack Stamper
Clark Public Utilities
Yes
Yes
Yes
Yes
Yes
No
I plan to vote affirmative but wanted to provide a suggestion. R3 is a requirement for the PC and TP to provide its Planning Assessment to the RC. I agree that this should be done, however, it is out of place in IRO-017. It should instead be included in the TPL-001 standard. Even if R3 is retained I encourage a process to eventually move it from IRO-017 to TPL-001.
Yes
Yes

Yes
No
Yes
No
Individual
Russell Schneider
Flathead Electric Cooperative, Inc.
No
Measures are improved with not having to cite a reason specifically, but still too much evidence burden on the receiving entity. The BA should have recordings already and some of these evidence requirements are duplicative.
Yes
No
This standard seems unnecessary and I do not support it. The obligations are already covered in other standards.
No
Again, DPs should not have evidence requirements when the BA/TOP is recording the other end of the line. Suggest deleting "Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format." from any DP measure.
Yes
Yes
No
Individual

Daniel Mason
HHWP
No
Draft 2 has not satisfactorily addressed the circumstances of small transmission operators. Most small TOPS operate very simple and predicatble systems, with the capacity for only minimal impacts on the BES. Draft Requirement TOP-001-3, R13 which will require such TOPs to perform, review and document real-time assessments every 30 minutes, unneccessarily burdens such TOPs with additional process, expense and resource requirements that will contribute no added reliability above and beyond the real-time assessment processes which Reliability Coordinators already have in place
Individual
Thomas Foltz
American Electric Power
No
R9: The reference “impacted interconnected NERC registered entities” needs to be consistent with the R8 terminology. We request that it be changed to “known impacted interconnected entities”. R10: The reference”sub-100 kV facilities identified as necessary by the Transmission Operator” needs to be clarified. Specifically, the phrase “as necessary” is ambiguous and subject to interpretation. Our negative vote is driven solely by the ambiguous reference “sub-100 kV facilities identified as necessary by the Transmission Operator”.
Yes

Yes
Yes
There are inconsistencies between the information provided in Figure 1 (p.5) and Table 1 (p.8) which may cause confusion. Consider for example the range of 800 to 900 MVA. In Figure 1, the Pre-Contingency flow in this range is considered “not acceptable” if longer than 4 hours. The text “not acceptable” is too strong, so rather than this language, we suggest using “action may need to be taken”. The rows in Table 1 do not clearly correspond to the example in Figure 1. It would appear that Table 1 should have four rows rather than three. As a result, it is unclear exactly which of the four ranges in Figure 1 correlate to the three Operating Plans provided in Table. In Figure 1, does the 800mva (24 hr rating) refer to a Normal or Emergency facility rating, or perhaps both? Please provide clarification.
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
No
SCE&G is in agreement with the SERC OC comments
No
SCE&G is in agreement with the SERC OC comments
Yes
SCE&G is in agreement with the SERC OC comments.
No
SCE&G is in agreement with the SERC OC comments
No
SCE&G is in agreement with the SERC OC comments
No
With regard to R13, we understand and support the need to do real-time assessments at least once every 30 minutes to avoid being in an unstudied state. However, if significant SCADA losses occur or an ICCP link is lost to a neighboring BA/TOP, the State Estimator solution can be affected to such a degree that a real-time assessment, with real-time data, may not be possible within 30 minutes. While this does not happen often, it does occur on occasion, but the requirement allows for NO exceptions to the 30 minute requirement. (As an example. the MOD-001 standard allows for a certain number of hours that ATC may not be recalculated without being in non-compliance).

No
SCE&G is in agreement with the SERC OC comments.
Yes
Yes
No
SCE&G is in agreement with the SERC OC comments
No
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual

John Brockhan
CenterPoint Energy Houston Electric LLC
No
See comment for TOP-001-3, R1
Yes
Yes
No
CenterPoint Energy does not agree with the structure of R1.2. While Protection System owners generally monitor the status of their Protection Systems CenterPoint Energy is very concerned that the proposed language would require Protection System owners to continuously notify their respective RC of the status of each Protection System which would be a very onerous task with questionable reliability benefit. In addition, for the RC to monitor the status of all Protection Systems in their area would be an overwhelming burden with little reliability benefit. The Company recognizes the need to notify an RC of a Protection System failure that impacts System reliability as required in PRC-001 and therefore recommends Protection Systems and Special Protection Systems be split into separate sub bullets as such: 1.2. Provisions for notification of current Protection System failures that impact System reliability. 1.3. Provisions for notification of current SPS status or degradation that impact System reliability. These comments would also apply to TOP-003-3.
Yes
No
In regards to Requirements R3 and R4, CenterPoint Energy feels the SDT has misinterpreted Paragraph 90 of the NOPR. CenterPoint Energy interprets the language in Paragraph 90 as speaking to the the Reliability Coordinator's role in outage coordination in the operational planning horizon. Paragraph 90 mentions generation outages being scheduled 3-5 years in advance and transmission outages being scheduled 1-3 years in advance as part of the planning process. Paragraph 90 goes on to mention the need for the Reliability Coordinator, in operational planning, to re-evaluate these planned outages through "… a month-ahead, week-ahead, and sometimes even a day-ahead approval process." CenterPoint Energy does not interpret Paragraph 90 to involve the Reliability Coordinator in the 1-5 year Near Term Planning Horizon process, but to follow its outage coordination process developed in R1.3 and R1.4 to evaluate any previously planned outages within its Wide Area and coordinate resolutions of identified outage conflicts in the Operations Planning Horizon. CenterPoint Energy recommends deletion of Requirements R3 and R4.
No
CenterPoint Energy feels Requirement R1 is general and may provide double jeopardy with other requirements that dictate specifics on when and under what circumstances TOPs are

required to act and direct others to act. CenterPoint Energy suggests reverting back to authoritative language requiring TOPs giving its Operating Personnel the authority to act, or direct others to act: “Each Transmission Operator shall provide its Operating Personnel with the authority to act, or direct others to act…” Another suggestion is to delete the Requirement completely due to its broad generality which is already included in the Functional Model, while keeping R3 and R4 for accountability of any Operating Instructions from the Transmission Operator to be followed. CenterPoint Energy also feels the language in R1, “…to ensure the reliability of its Transmission Operator Area” puts an unavoidable burden on the TOP for when an unexpected event occurs. CenterPoint Energy suggests changing ‘ensure’ to ‘maintain’. These comments would also apply to IRO-001-4, R1. R10. CenterPoint Energy feels monitoring Facilities reaching into a neighboring Transmission Operator Area needs more direction. The term ‘as necessary’ is too vague for a TOP to determine how far into a neighboring Area or what specific equipment contained in another TOP Area it would need to monitor to determine SOL exceedances. CenterPoint Energy also feels it is the RC function to monitor and determine any reliability issues which may overlap or cascade between TOP Areas as they have the Wide Area view. CenterPoint Energy recommends removing ‘neighboring areas’ from R10.
Yes
No
See comments for IRO-010-2.
No
No
Individual
Denise M. Lietz
Puget Sound Energy
No
The effective date for requirements R1 and R2 should be staggered (similar to the drafting team's approach to requirement R1 and R2 of IRO-010-2). It will be very difficult for a BA or TOP to comply with the RC's outage process if that process is finalized on or near the effective date for requirement R2. Requirement R2 is too broad and should be limited to "performing the applicable functions" of the RC's outage coordination process. In addition,

what will happen in the case that the RC specifies deadlines or processes that a BA or TOP cannot meet or requirements that are unrelated to outage coordination? To address this issue, in part, the RC should be required to collaborate with the BAs and TOPs in its area during the development of and revisions to the outage coordination process. This may not address all the issues that could arise, but would at least provide BAs and TOPs with time to address shortcomings in their processes prior to incurring a standard violation.
No
It is nearly impossible for entities to comply with requirements R1 and R2 of TOP-001-3 as currently drafted. This issue is highlighted (not corrected) by the draft RSAW's approach of evaluating compliance only during events. RSAWs are only guidance - reading footnote 1 of the current RSAW template makes it clear that the RSAW is a reference document only and entities cannot depend on the approach outlined there to resolve ambiguities associated with a requirement. The place to resolve ambiguities is in the standard's language, not in the RSAW. An entity must comply with any requirement at all times; it does not matter if the enforcement authority only checks compliance during certain periods. If an entity fails to comply with the requirement at any other time, that entity is obligated to self-report the violation. In this situation, then, each entity must "ensure" the reliability of its area 24/7/365 to be compliant with requirement R1 or R2. This means that any reliability event could reflect an entity's failure to comply with R1 or R2 because the entity failed to ensure the reliability of its area during that event. But can any entity really ensure the reliability of its area? This just doesn't seem possible because there are so many factors outside of an entity's control that can affect the reliability - for example, equipment failure or a fire along transmission lines. In addition, the burden of monitoring compliance based on the proposed language is immense. Requirements R1 and R2 of the currently effective TOP-001-1a require entities to take action to "alleviate operating emergencies". This is a high bar, but not so high that an entity cannot comply when factors beyond its control affect the reliability of its area. In addition, using this language in the proposed standard would be consistent with the RSAW's approach and ease the associated compliance monitoring obligation, while still requiring an entity to act to protect the reliability of its area.
The language of measure M2 is inconsistent with requirement R2 – it is missing the word "exceedance" after the phrase "System Operating Limits (SOLs)".
Yes
As discussed in the comments addressing IRO-017, requirements R1 and R2 of that proposed standard should be phased with requirement R1 becoming effective prior to R2.. Just as in IRO-010, the BAs and TOPs subject to requirement R2 are likely to need some time to implement the processes specified in RC's outage coordination process. In addition, connecting the implementation time to COM-001-2 if this group of standards is approved prior to or concurrent with COM-001-2 and COM-002-4 could result in a short implementation time. For example, say that FERC approval of both the COM standards and

the IRO/TOP standards becomes effective on June 30, 2015. According to the implementation plan, the standards will “become effective concurrently with COM-001-2 and the definition of Operating Instruction”. The effective date of COM-001-2 is “first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities…”, which would be October 1, 2015 in this example. There is some ambiguity with this result since the term Operating Instruction is not used in COM-001-2, but in any case, using the effective date of COM-002-4, which is more consistent with the implementation period of the IRO/TOP standards, seems more appropriate.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Yes
No
Individual
David Thorne
Pepco Holdings Inc.

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Yes
No
Individual
Dave Willis
Idaho Power Company
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
No
No
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Although proposed IRO-008-2 is not applicable to ATC, changes were made by the SDT to Requirement R1 and the proposed term “Reliability Coordinator Wide Area” that addressed ATC’s comments in response to the SDT’s 1st posting.
Yes
No
ATC requests the SDT to consider making the following modifications to the proposed Requirements R3 and R4: R3 – To be consistent with the “Long-term Planning” Time Horizon in Requirement R4 and due to Requirement R3’s association with the long-term horizon Planning Assessments, ATC suggests that the Time Horizon for Requirement R3 be changed to “Long-term Planning.” R4 – To be more consistent with paragraph 90 of the FERC NOPR and because the term “planned outages” has no specific NERC or industry-wide meaning, ATC suggests that the wording of “planned outages” in Requirement R4 be replaced with “scheduled generation, transmission maintenance and transmission construction outages.”
No
ATC requests the SDT to consider making the following changes to the proposed Requirement R10 based on the corresponding technical rationale. It is ATC’s understanding that the intention of the SDT is to not require each Transmission Operator to monitor all Facilities and all Special Protection Systems in the neighboring TOP areas. However, the

structure of the sentence in Requirement R10 does not provide this clarity. Rather, the sentence requires each TOP to monitor all Facilities, all Special Protection Systems and a subset of sub-100kV facilities for its TOP area and its neighboring TOP areas. If the TOP is to be given discretion on which neighboring Facilities and Special Protection Systems are to be monitored, then ATC suggests that Requirement R10 be modified as: “R10. Each Transmission Operator shall determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area by monitoring: R10.1 Within its Transmission Operator Area: R10.1.1 Facilities R10.1.2 Status of all Special Protection Systems R10.1.3 Sub-100 kV facilities identified as necessary by the Transmission Operator R10.2 Within neighboring Transmission Operator Areas and identified as necessary by the Transmission Operator: R10.2.1 Facilities R10.2.2 Status of Special Protection Systems R10.2.2 Sub-100kV facilities” Please Note: ATC also requested via the RSAW Feedback Form to modify the RSAW’s evidence listing for proposed Standard TOP-001-3 to address inconsistencies with the language of Requirement R10 or any modifications to this language based on ATC’s comments. For example, if the R10 language is left unchanged, the Facilities evidence should be “all Facilities within its TOP area and those Facilities in neighboring TOP areas determined necessary by the TOP.” This structure would also be applied to Special Protection Systems. For sub-100kV facilities, the evidence should be “those sub-100kV facilities determined necessary by the TOP” without a need to reference its TOP area or neighboring TOP areas since that is the plain reading of the requirement.
Yes
Yes
No
No
Group
Seattle City Light
Paul Haase
Yes
SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
Yes
SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
Yes

SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation. For IRO-101-2, SCL asks that the implementation times be extended from nine and twelve months to eighteen and twenty-four months, because it may take longer than one year to negotiate and impelment the necessary data exchange agreements among impacted entities. SCL's recommended implementation language is as follows: Section 5. Proposed Effective Date. Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Yes
SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation.
Yes
No
SCL appreciates the efforts of the Standard Drafting Team to increase the clarity of the TOP and IRO Standards while generaly reducing the burden of compliance documentation. However for TOP-001-3, SCL believes a changes are required before this Standard provides the clarity and effectiveness of the others. Specifically SCL asks for changes as follow: Requirement R9 covers too broad a scope to be useful. The phrase “…outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels…” is all encompassing. If each BA or TOP was calling the RC every time there was the slightest glich with telemetering or every time an ICCP link, microwave channel or EIDE data signal was cycled for maintenance or some type of momentary signal fade, the RC’s phone would be ringing continually. The intent of this requirement is to be sure all entities are aware of a loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 (as written, but also see below)

is sufficient to meet the intent. SCL suggests the following re-wording: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of any scheduled and sustained outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. Requirement R13, SCL suggests changing 30 minutes to 60 minutes. Usually generation, load and interchange are estimates and adjusted on hourly basis so performing assessment every 30 minutes is not necessary and could prove an onerous requirement for TOPs without providing any real reliability benefits. SCL suggests the following re-wording: R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 60 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]
Yes
Yes
SCL appreciates the efforts of the Standard Drafting Team in crafting IRO and TOP Standards that are clearer while generally reducing the burden of compliance documentation. For TOP-003-3, while somewhat burdensome, this Standard makes the process for requiring entities to request and provide real time reliability data standardized. SCL is concerned with the implementation period allowed for this Standard, because in our experience it has taken longer than 12 months to negotiate and implement the necessary data exchange agreements between entities. As such, SCL suggests extending the periods allowed to eighteen and twenty-four months, re-wording the effective date section as follows: Section 5. Effective Date. All requirements except Requirements R5 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved gy an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R5 shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date that the standard is approved gy an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction
No
SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards.
Yes

SCL asks that the Implementation Plan be revised to conform with our recommendations that the implementation periods and effective dates for IRO-010-2 and TOP-003-3 be extended to eighteen and twenty-four months (to allow sufficient time to negotiate and implement data exchange agreements among entities), as indicated above.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration , LP
No
Ingleside Cogeneration LP (ICLP) believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in IRO-001-4 R2 and R3. In R2/R3, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on IRO-001-4's requirements to execute an Operating Instruction – and not so much COM-002-4's oversight of the protocols to use. However, an Operating Instruction can be any communication to "change or preserve the state, status, output, or input" of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to IRO-001-4, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with "this is a mandatory Operating Instruction" should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome – particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.
No
ICLP agrees there are times where the RC will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason – and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of RCs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may

be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned RC – that a full evaluation by an independent panel would take place afterwards.
No
ICLP believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in TOP-001-3 R3 through R6. In R3-R6, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on TOP-001-3's requirements to execute an Operating Instruction – and not so much COM-002-4's oversight of the protocols to use. However, an Operating Instruction can be any communication to "change or preserve the state, status, output, or input" of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to TOP-001-3, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with "this is a mandatory Operating Instruction" should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome – particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.
No
ICLP agrees there are times where the TOP will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason – and eliminates the possibility that the TOP can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of TOPs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned TOP – that a full evaluation by an independent panel would take place afterwards.

Individual
Robert Fox on behalf of David Austin
Northern Indiana Public Service Company (NIPSCO)
Yes
Yes
Yes
Yes
Yes
Yes
No
NIPSCO feels R10 should align with the Operational Planning Analysis Requirement and include a reason such as "to determine SOL exceedances". NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
No
TOP-002-4 R1 requires that you perform an analysis that identifies SOL exceedances, but SOLs are not explicitly included as a study input in the Operational Planning Analysis definition, only Facility Ratings, which are only a subset of FAC-014-2 R2 SOLs. There seems to be operating plans created by the TOP in R2 and operating plans created by the RC in IRO-008-2. How are comflicts resolved if the results differ? How does the R2 Operating Pland mesh with the operating plan specified in VAR-001-4 R1? Are they the same?
Yes
No
Yes
Yes
NIPSCO is voting against approving the definitions for the following reasons: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and

equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. See our comments on TOP-002 for more informaiton. 2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
No
R3 contains a requirement for the PC/TP to provide a copy of its assessment to the RC. This should be eliminated from this standard and merged into R8 of TPL that already requires the PC/TP to distribute the assessment with other entities. R4 – Planning Assessment performed as per TPL-001-4 is applicable to Long-term Planning time horizon (>12 months) and has no overlap with the Operations Planning time horizon (day-ahead to 12 months). Therefore, it is not clear how Planning Assessment would be an appropriate "tool" to address the outage coordination reliability objective in R4 in the Operations Planning time horizon.
No
In R7, how is the entity receiving the request able to know if the requesting entity has indeed implemented its emergency procedures? Suggest removing that qualifier, or change the requirement to state that "Each Transmission Operator shall assist Transmission Operators experiencing an Emergency, if requested, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements." R10 is not written clearly. Suggest restructuring. Each Transmission Operator shall monitor: o Facilities (including sub-100 kV facilities needed to maintain reliability) within its Transmission Operator Area and o Facilities (including sub-100 kV facilities needed to maintain reliability) in neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area o Status of Special Protection Systems within its Transmission Operator Area R16 & R17 should state "...approve or defer/deny…" Is R18 only for derived limits or if there is a difference in any limit? Or is the intent of the requirement to be " … when limits are derived and there are differences when comparing solutions."?
No

R2 – is the descriptor “potential” needed? Do R6 & R7 need a qualifier “…by the time frame established by the RC”?
No
Individual
Leonard Kula
Independent Electricity System Operator
Yes
Yes
No
a. R6 and all of its VSL: The reference to “as identified in identified in Requirement R6” should be revised to “as identified in Requirement R5”. b. We wish to reiterate our previous comment on the inconsistent language used between the LOWER VSL for Requirement R6 (in which the word “Emergency” is used) and Requirement R6 (which does not use the word “Emergency”). R6 .Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. LOWER VSL for R6. The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan “when the Emergency identified in Requirement R6 was prevented or mitigated.” For consistency, please revise VSL to read “when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated”. c. The language between R4 and its VSL is inconsistent. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC “perform” to “ensure that a Real-time Assessment is performed”. However, the VSL still assesses the condition that the RC did not “perform” as opposed to did not “ensure that the Real-time Assessment was performed”. Please revise as appropriate.
Yes
No
a. We generally agree with the changes made to IRO-014-3. However, the replacement of “other” with “adjacent” may leave a reliability gap. For example, the notification of Transmission Loading Relief may require “notification or coordination of actions” by, and

can have an impact on, RCs other than just the adjacent RCs. Since the words “may impact” already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word “other” into R1, replacing “adjacent”. b. We do not have a preference, but we ask the SDT to review the use of the phrase “Wide Area” in IRO-008-2 (and other IRO standards) and the phrase “Reliability Coordinator Area” in IRO-014-3. If these phrases are expected or interpreted to be synonymous, we suggest using one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion. c. Retention Period: We are unable to find the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors.
No
During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT’s response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are concerned with Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
No
a. During the last posting, we expressed a concern over the ambiguity in R9 as the phrase “between the affected entities” can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, we suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities b. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.

Yes
Yes
No
During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT’s response indicates that “it has revised the whitepaper to include “as necessary and appropriate”. However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that “All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.” We speculate that the insertion of “as necessary and appropriate” to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still has up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, “However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating).” We urge the SDT to reassess whether or not the “as necessary and appropriate” should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.
Yes
Yes
During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT’s response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid. In other word, there does not exist any

"proven reliable power system limits" as stated in R4 of TOP-002-4. While the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon may seem appropriate, the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state. If R4 in TOP-004-2 is retired, it leaves a potential reliability gap. The white paper does not mandate the proper and necessary action to "restore operations to respect proven reliable power system limits within 30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. We are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. Please advise.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4. R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
No
As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the Plan is modified or not. To prevent unnecessary duplication, recommend modifying R6 as follows to allow the Transmission Operators and Reliability Coordinators to develop an arrangement or schedule. R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator in accordance with the Reliability Coordinator's schedule.

Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Rationale for R2 and R3 should be modified for consistency with the removal of the TSP. R2 : Replace "compliance with the Operating Instructions" with "they" referring to the instructions. Compliance is not something that can be "physically implemented". Instructions can. Also for consistency with M2 M2 : Remove the Transmission Service Provider from the second portion of the measure (2 occurrences) Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Compliance section 1.3 : Remove all occurrences of "Transmission Service Provider". (Would have been best achieved by a "search and replace"…)
No
Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).
No
R6 : Replace "Reliability Coordinator Wide Area" by "Wide Area" for consistency with modifications made to R1. Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R4, R6 and R8 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3. Associated Documents : The content of the white paper shouldn't be included in the standard. A reference with an hyperlink would be enough.
No
R1 : Replace the last sentence with "The data specification shall include but is not be limited to:. Otherwise the "shall" applies to "not be limited to". That would mean that the data specification shall include other items that are not listed. Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Compliance section 1.3 : Remove Planning Coordinator and Transmission Planner Table of Compliance Elements: VSLs for R2 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.

No
Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Associated Documents : The content of the white paper shouldn't be included in the standard. A reference with an hyperlink would be enough.
Yes
No
In R4, modify the second "its Transmission Operator" by "that Transmission Operator" for consistency with the wording of R6. Also modify corresponding element in the Table of Compliance Elements. In R9 and M9, remove the expression "interconnected NERC registered" for consistency with IERP recommendation regarding TOP-002-4 R3 In R17, replace "analysis" by "Real-time Assessment" for consistency with R16. R18 is unclear. What does "where there is a difference in SOLs" mean? Difference in SOLs compared to which SOL? A "difference" implies a comparison between two SOLs. That portion of the requirement should be clarified. The rationale for R19 and R20, which are related to data exchange capabilities, states that they're added for consistency with IRO-002-4 R2 whereas R2 addresses RC's System Operator authority. In R19 and R20 why the use of "Transmission Operator Area (Balancing Authority Area)" for both requirements? R19 should say "Transmission Operator Area" and R20 should say "Balancing Authority Area" for consistency with associated Measures. Compliance section 1.2 : As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R8 and R9 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. Example: "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted Transmission Operators or other known impacted Balancing Authorities that the Responsible Entity did not inform of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas or Balancing Authority Areas when conditions did permit such communications : High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" The whole wording of the requirement could be omitted for more clarity : "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted entities that the Responsible Entity did not inform in accordance with that requirement : High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The

lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" Associated Documents : The content of the white paper shouldn't be included in the standard. A reference with an hyperlink would be enough.
No
In R1, replace "shall have an Operational Planning Analysis" by "shall perform an Operational…" In R2, replace "as required in Requirement R1" by "performed in requirement R1" for consistency with M2. Do not capitalize "requirement" since it is not a defined term. R6 : Why not put that requirement in R2? Simply add "…and provide that plan to its Reliability Coordinator" to the end of R2 (same for R7). The standard would be more clear and concise. Compliance section 1.2 : As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements : See comment made for TOP-001-3 Associated Documents : The content of the white paper shouldn't be included in the standard. A reference with an hyperlink would be enough.
No
Compliance section 1.2 : As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).
Yes
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
No
R1 – We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Reliability Coordinator takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R1 specifically to those entities identified in Requirements R2 and R3.We recommend the following rewrite: ‘Each Reliability Coordinator shall act, or direct others as identified in Requirements R2 and R3 to act, by issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area. ‘ Rationale Box for Requirements R2 & R3 – The Rationale Box for Requirements R2 and R3 does not match the language in the requirements. There is no mention of the Transmission Service Provider in the requirements. It only appears in Measures M2 and M3. The IRO Five

Year Review Team had recommended adding Transmission Service Provider to Requirements R2 and R3 to allow the retirement of IRO-004-2. With the removal of the Transmission Service Provider in Requirements R2 and R3, can the retirement of IRO-004-2 move forward?
No
M1 – Capitalize Real-time in the last line of Measure M1.
No
1.3 Data Retention – Hyphenate 30- and 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Yes
Yes
No
R2/M2 – Make Reliability Coordinator in Requirement R2 and Measure M2 possessive. The requirement should read '…in its Reliability Coordinator's outage coordination process.'R4 – To focus the coordination effort of the Reliability Coordinator on BES issues we recommend modifying the wording of R4 to state '…for identified issues or conflicts on the BES with planned outages…'
No
R1 – We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Transmission Operator takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R1 specifically to those entities identified in Requirements R3 and R4. We recommend the following rewrite: 'Each Transmission Operator shall act, or direct others as identified in Requirements R3 and R4 to act, by issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area. ' R2 – We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Balancing Authority takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R2 specifically to those entities identified in Requirements R5 and R6. We recommend the following rewrite: 'Each Balancing Authority shall act, or direct others as identified in Requirements R5 and R6 to act, by issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area. ' R9 – We feel that the use of impacted interconnected entities is too broad for the notification requirement. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Additionally, the term 'NERC registered' in Requirement R9 and Measure M9 should be deleted. This term was deleted in IRO-008-2, Requirement R4 and TOP-002-4, Requirement R3. We recommend rewording the requirement to read: 'Each Balancing Authority and

Transmission Operator shall notify its Reliability Coordinator and known impacted entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities lasting 30 minutes or longer.' Should Requirement R9 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R10 – We have concerns with the existing language in Requirement R10 which when applied in the real-world of today's audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn't model enough of the neighboring TOP's Area? Isn't this really the function of the RC and aren't we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: 'Each Transmission Operator shall monitor 10.1 Facilities within its TOP Area, 10.2 status of Special Protection Systems identified as necessary by the Transmission Operator, 10.3 sub-100 kV facilities identified as necessary by the Transmission Operator, and 10.4 Facilities within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator as necessary to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.' Rationale Box for R14 – The newly inserted sentence in Rationale Box for R14 doesn't completely present the overall picture of the Operating Plan as contained in the Associated Documents at the back of the standard. We propose an additional sentence, as indicated below, be included in the Rationale Box. '…These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments (OPA) required per proposed TOP-002-4 or other assessments. The Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). The intent is not to have a…' R18 – Should Requirement R18 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R19 – Delete the parenthetical Balancing Authority in Requirement R19. R20 – Delete Transmission Operator and the parentheses around Balancing Authority in Requirement R20.
No
R4 – We suggest that load forecast uncertainty and resource uncertainty be added to the list of Parts for Requirement R4. 1.3 Data Retention – Hyphenate 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Yes
Yes
First full paragraph on Page 3, we suggest the following rewrite for the last sentence in that paragraph. 'Conversely, if an area is not at risk of instability, no Facilities are approaching their thermal Facility Ratings but the area is prone to pre- or post-Contingency low voltage

conditions, then the voltage limits in that area are the limiting SOLs.' We also suggest deleting the 1st sentence in the following paragraph on Page 3. The paragraph flows better without it. We further suggest the following rewording in what would then be the 2nd sentence in the paragraph. 'How an entity remains within these SOLs can vary depending on the operating practices and planning strategies employed by that entity.' In 4. Voltage Stability Limits, replace the 2nd sentence with the following: 'Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met.'
No
IRO-008-2 R4 – Change the Severe VSL for new Requirement R4 (old R5) to read '…more than three…' or '…four or more…' in lieu of '…three or more…'. The High VSL already uses three. IRO-014-3 R3 – The lead-in for the VSLs for Requirement R3 refers to Requirement R5. This reference should be to Requirement R3. R7 – Change the Severe VSL for Requirement R7 to read '…Coordinator had implemented…' and '…or would have violated safety…'. IRO-017-1 R2 – Make Reliability Coordinator possessive in the Severe VSL for Requirement R2. TOP-001-3 R8 – Delete 'other' in the VSLs for Requirement R8 referring to '…other known impacted Balancing Authorities…' and '…other Balancing Authorities…'. The use of 'other' only applies to references to Transmission Operator. Also in the VSLs for R8, change 'less' to 'greater' such that the Lower VSL would read: 'The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the affected known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.' (This particular change applies to all VSLs in R8, R9, R19 and R20 as well as the VSLs for IRO-002-4, R1; IRO-008-2, R3, R5, R6; IRO-010-2, R2; TOP-002-4, R3, R5; TOP-003-3, R3, R4.) R9 – Delete the term 'NERC registered' in the VSLs for Requirement R9. (See comment in Question 7 above. R13 – Change the Severe VSL for Requirement R13 to read '…more than three…' or '…four or more…' in lieu of '…three or more…'. The High VSL already uses three. R19/R20 – Replace 'applicable' with 'identified' in the VSLs for Requirements R19 and R20. The use of 'identified' parallels the language in the requirements. TOP-002-4 R3 – Replace 'NERC' with 'entities' in the High and Severe VSLs for Requirement R3.
Yes
The definition of Special Protection System (SPS) is being revised to Remedial Action Scheme (RAS) yet this package of standards continues to use SPS. What process will be used to make the transition to RAS when the new definition is approved? Similarly, Load-Serving Entity will soon be eliminated as a registered function at NERC. How will this change be reflected in the standards?
Group
Florida Municipal Power Agency
Carol Chinn
Yes

Yes
The previous suggestion from the FRCC Operating committee was not taken regarding the “to approve” language in R3. As drafted this does not cover the full spectrum of authority needed by the RC. FMPA suggests replacing the words “to approve” with “over” to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators.
No
It seems the SDT did not understand FMPA’s previous comment regarding R1. FMPA’s comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase “N-1 Contingency planning” no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the RC’s OPA supposed to consider N-2 events? N-3? Loss of an entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs and IROLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase “in accordance with its SOL Methodology”. Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards. The number of contingencies to be studied is also absent from the definition of Real-time Assessment.
Yes
Yes
Yes
Yes
In R16 and R17, FMPA suggests replacing the words “to approve” with “over” to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators. In R16, FMPA suggests replacing “Real-time Assessment” with “analysis” to be consistent with the similar requirements for the RC and BA. FMPA notes that the number of contingencies to be studied is absent from the definition of Real-time Assessment, see comments on TOP-002-4.
No
It seems the SDT did not understand FMPA’s previous comment regarding R1. FMPA’s comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase “N-1 Contingency planning” no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the TOP’s OPA supposed to consider N-2 events? N-3? Loss of an

entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase “in accordance with its RC’s SOL Methodology”. Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards.
Yes
FMPA supports the comments of FRCC Operating Committee (Member Services).
No
FMPA appreciates the good work of the SDT in streamlining and improving the clarity of these standards.
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Requirement R4: Texas Reliability Entity, Inc. (Texas RE) requests that the SDT consider replacing the term “sub-100 kV” with “non-BES” to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to “sub-100 kV” facilities is for those facilities that have been intentionally included in the BES due to their criticality.
No
1) Requirement R1: The SDT changed “or” to “and” within the phrase “System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLS)” based on a comment. Neither the commenter nor the SDT provided justification for the change. Texas RE does not agree with the change because if either SOLs OR IROLs are exceeded then the assessment should be performed; not just if both are exceeded. Texas RE requests that the change be rejected and the original language be reinstated or explanation of why the change is correct. 2) Section 1.3. Data Retention: Texas RE does not agree with the change of data retention for R1, R2, R3, R5 and R6 from a rolling six months to a rolling 90 calendar days. The six-month requirement was aligned with the Data Retention and Sampling Team (DRAST) white paper, which indicates a six-month rolling period for high volume data, and 90-days for voice and audio recordings. The same comment applies for R4, which was changed from 90 days to a rolling 30 days.

Yes
Requirement R1.1: Texas RE requests that the SDT consider replacing the term “sub-100 kV” with “non-BES” to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to “sub-100 kV” facilities is for those facilities that have been intentionally included in the BES due to their criticality.
Yes
Requirements R1 and R2: Texas RE requests the SDT consider whether including Same-Day Operations in the Time Horizon is appropriate. The measures for R1 and R2 are focused on the maintenance of the Operating Procedures, Operating Processes and Operating Plans and not on any specific same-day actions that need to be taken. Texas RE suggests that Same-Day Operations be removed from the Time Horizon for R1 and R2. The Time Horizon of Operations Planning is correct. If the SDT disagrees with the suggested removal of the Same-Day Operations Time Horizon then we request an explanation of why it is appropriate to include it.
Yes
No
1) Requirement R8: Texas RE disagrees with the addition of the word “known” to impacted TOPs and BAs. Within the interconnected system, a TOP may not always know who is impacted. It would be prudent to also notify TOPs who may be impacted. We suggest the SDT keep the original language “impacted Transmission Operators.” Requirement R9 did not add “known” to the phrase “impacted interconnected NERC registered entities” which is inconsistent with R8. Texas RE recommends that R8 and R9 should be consistent when the SDT determines if “known” should be included or not. 2) Requirement R9, M9 and R9 VSL: Suggest the SDT remove “NERC registered” to be consistent with other standards in this project. 3) Requirements R9 and M9: The two paragraphs need to be consistent and cover both planned and unplanned outages. Texas RE recommends changing the two paragraphs so that “outages” is preceded by “planned and unplanned.” 4) Requirement R10: The use of the term “within its Transmission Operator Area” in R10 may lead to potential conflicts and reliability gaps, specifically for monitoring of SPS’s. For example, an SPS owned by a GO/GOP would not have to be monitored by a TOP since it is not within its Transmission Operator Area (i.e. the generator is not a “Transmission” asset per the definition), even though the operation or misoperation of the SPS may lead to SOL violations within the TOP area. Texas RE suggests clarifying language be added by the SDT to assure that a TOP monitors all facilities and Special Protection Systems within its area; not just those that fall under the definition of transmission asset. 5) Requirement R10: Texas RE requests that the SDT consider replacing the term “sub-100 kV” with “non-BES” to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large

loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality. The SDT may also consider modifying the language to state "identified as necessary by the Transmission Operator or Reliability Coordinator." 6) Requirements R13, R14, R15: Texas RE requests the SDT consider whether there should be a similar requirement for a BA to perform a Real-time Assessment. The following questions are submitted to assist the SDT's assessment of our request. In real-time, how will a BA control frequency or know if it is experiencing or about to experience a capacity emergency unless it is performing such an assessment? For R14, how does the BA initiate its Operating Plan for an EEA unless it sees a capacity deficiency through a Real-time Assessment? For R15, how does the BA notify the RC of a capacity emergency unless it sees a capacity deficiency through a Real-time Assessment? 7) Requirement R19: The term "(Balancing Authority Area)" appears to be a typo and should be removed. 8) Requirement R20: The term "Transmission Operator Area (Balancing Authority Area)" appears to be a typo and should be replaced with "Balancing Authority Area."
No
1) Requirement R4: Texas RE reiterates our previous comments regarding adding a new requirement for the BA to have an Operational Planning Analysis (in line with R1 language for the TOP). The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion. 2) Requirement R6: Texas RE requests the SDT consider whether the TOP should also be required to provide its Operating Plan(s) for next-day operations to the BA. The following questions are submitted to assist the SDT's assessment of our request. Without the TOP Operating Plan, how will a BA perform its assessment of delivery capability if it does not have predicted or planned transmission outages from the TOP(s)? 3) Requirement R7: Texas RE requests the SDT consider whether the BA should also be required to provide its Operating Plan(s) to TOPs. Without the BA Operating Plan, it is unclear how a TOP will perform its assessment to determine if there will be any SOL exceedances if it does not have the predicted generation dispatch and demand patterns from the BA.
No
1) Requirement R1.1: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality? 2) Requirement R2: Texas RE reiterates our previous comments about replacing "analysis functions" with

“Operational Planning Analysis.” This comment relates to the TOP-002-4, R4 comment for requiring a BA to have an Operational Planning Analysis. The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion.
No
No
1) IRO-008-2, Requirement R4 VSLs - Suggest the SDT remove “NERC registered” to be consistent with the Requirement R4 language and other standards in this project. The words were removed once in the VSLs but they occur twice in the VSLs. 2) IRO-008-2, Requirement R6 VSL – Texas RE requests the SDT consider revising the R6 VSL to contain only a Severe VSL. Texas RE submits that any failure to notify of IROL or SOL exceedances could result in cascading outages. 3) TOP-001-3, Requirements R8 and R9 VSLs – Texas RE recommends removing each instance of the phrase “whichever is less” from the R8 and R9 VSLs or at least from the Severe VSLs. At worst, it appears to nullify intent stated by the SDT for R8 and R9 that a situation where a small entity did not inform just one affected entity should be a Severe violation. At best, it adds no clarity to assessing violation severity levels. Specifically, for R8, if a small TOP with 1 known impacted other TOP did not notify that impacted TOP then it’s 100% which should make it a Severe VSL. However, the phrase “whichever is less” appears to kick it back to a Lower VSL because it is only one failure to inform, not four or more, which is less. It’s important to note that TOP-002-4, Requirements R3 and R5 do not include the phrase “whichever is less” in the Severe VSL language which is presumably a recognition that it doesn’t apply in the Severe VSL. 4) TOP-002-4, Requirements R3 and R5 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R3 and R5 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs. 5) TOP-003-3, Requirements R3 and R4 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R3 and R4 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs. 6) IRO-010-2, Requirement R2 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R2 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs.
Yes
1) Texas RE appreciates the work that the SDT has done to address the comments received from industry during the previous ballot and comment period. Thank you for the time you have put into working towards making a set of steady state TOP and IRO standards. 2) Texas RE has one general comment regarding data retention for all the standards within this project. Texas RE recommends the SDT consider aligning the retention periods with the Data Retention and Sampling Team (DRAST) white paper which indicates a 4-year retention period for data with limited exemptions, such as a 6-month rolling period for high volume

data, and 90-days for voice and audio recordings. 3) Operational Planning Analysis definition: Texas RE requests the SDT provide explanation for why the phrase "may be performed either a day ahead or as much as 12 months ahead" was removed from the proposed definition. The phrase is included in the current Glossary defined term. Following up on our comment from the previous ballot and comment period, Texas RE still asserts that without that phrase the time frame for one day up to 12 months is not accounted for.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Please see question 7.
Yes
Yes
Yes
Yes
To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4. R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
Yes
We believe that requirement R9 to notify impacted entities of planned outages of telemetering equipment, control equipment, and monitoring and assessment capabilities is too broad. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Therefore, we propose the following revision to R9: R9 Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted entities of “planned outages” of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities lasting 30 minutes or longer. Requirements R16 and R17 require that TOP and BA give authority to their system operators to approve planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Using the same rationale of R9, we propose to revise R16 and R17 as follow: R16 Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance last 30

minutes or longer of its monitoring, telecommunication, and Real-time Assessment capabilities. R17 Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its monitoring, telecommunications, and analysis capabilities. Similarly, IRO-002-4 requirement R2 should also be revised as follow: R2 Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its telecommunication, monitoring and analysis capabilities.
Yes
As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the Plan is modified or not. To prevent unnecessary duplication as well as allow for greater flexibility in the requirement, recommend modifying R6 as follows to allow the Transmission Operators and Reliability Coordinators to develop an arrangement or schedule. R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator in accordance with the Reliability Coordinator’s schedule.
Yes
Yes
Yes
No
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
The groups represented by the FRCC Operating Committee support IRO-001-4 revisions in principle, however we seek clarification on the potential interpretations of the term “Operating Instructions” and the potential administrative impact to normal and emergency BES operations needed to demonstrate compliance as stipulated in the Measures.
Yes
However, R5 requires “synchronized information systems”. The FRCC Operating Committee seeks clarification from the drafting team on what constitutes a “synchronized information system”. Consider replacing the word “synchronized” with “coordinated.”
Yes
Yes

Yes
Yes
Yes
The FRCC Operating Committee supports a majority of these proposed requirements. However, the OC does not support the language in new requirement R9 and finds that the mapping from current requirement (TOP-003-1 R3) is incomplete and needs to be addressed by the standard drafting team. The language in the existing TOP-003-1 R3 is more precise and should remain as is. If the SDT is attempting to address the comments from the SW Outage Report Recommendations “TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities,” they should create a separate requirement to reflect the notification for loss of Real-time Assessment capabilities. At a minimum, the requirement should state “telemetering and control equipment”, rather than “telemetering equipment, control equipment”. This will add clarification to the type of equipment being addressed in the requirement. In addition, the word “planned” from M9 was not removed as noted in SDT responses. We also recommend removing the words “interconnected NERC Registered”. The word “impacted” reflects who should be notified. The current mapping of existing TOP-003-1 R3 to TOP-001-3 R9 does not accurately reflect the original intent of TOP-003-1 R3. R19 and R20 have some inconsistencies with referencing TOPs and BAs.
Yes
Yes
Yes
We suggest adding the following clarification to page 2 of the white paper: -Remove the terms “Normal (continuous)” from the Pre-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. -Remove the terms “Emergency (short term)” from the Post-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. We also suggest that the paper be reviewed for consistency when using the terms “pre-contingency” and “post-contingency”. Interchanging the use and context causes confusion – i.e. Change the column headers in Table 1, “Pre-Contingency Loading” to “Pre-Contingency Mitigation” and change “Post-Contingency Loading” to “Post Contingency Mitigation”. Another example would be to use “Real-Time flow” instead of “Pre-Contingency Flow”. Also in Table 1, under the ‘Emergency (4hr)” row – “Post Contingency Loading” column change “all” to “available”.
Yes

The comments provided herein are consensus comments of the FRCC Operating Committee entity representatives. Our responses to the above questions in no way intends to convey how individual FRCC OC member entities will vote on the standards being proposed. Thank you for your efforts.
Individual
Joshua Andersen
Salt River Project
Yes
Yes
Yes
Yes
Yes
No
Salt River Project (SRP) has a general concern with the R1 requirement for the Reliability Coordinator to develop, implement and maintain an outage coordination process for generation and Transmission outages. Specifically, SRP is concerned if the RC will have the ability to approve or deny outages.
Yes
Yes
No
The Requirements go way beyond the established NERC process in creating and modifying current standards. The goal is stated to create reliability standards that “use a results based approach that focuses on performance, risk management and entity capabilities”. I suggest that the requirements in TOP-003-3 do not meet this threshold in that the burdensome requirements do not result in a significant enhancement in reliability nor do they consider entity capabilities. I suggest that the SDT work on creating a simple and efficient process to verify that necessary operating data is being freely exchanged as needed among entities. A suggestion might be to create a regional committee to address those conflicts that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this Standard.
No

Yes
No
Individual
Eric Sutlief
Consumers Energy Company
Yes
Yes
No
I have a concern with the evidence for compliance with Requirement 4. The Standard as written does not clearly define parties who must be notified. The reference to the Operations Plan does not require the inclusion of any non-registered entity.
Yes
Yes
Yes
No
In Requirement 1 and 2 the term reliability provides a vague stipulation. "… by issuing Operating Instructions to ensure the reliability of its Transmission Operating Area." I don't know if language can be suggested at this point, but I would prefer to see "stability" rather than "reliability".
Yes
Yes
No
Yes
No
Group
ACES Standards Collaborators

Ben Engelby
No
(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) Requirement R1 should be revised by removing the words “direct others to act” and stating that the RC shall issue Operating Instructions. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. For example, by stating that the RC shall act or direct others to act by issuing an Operating Instruction, the RC is limited only to this option. We recommend alternative language for this requirement, “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” (3) Requirement R1’s language of requiring the RC to “ensure reliability” could be used as a zero defect standard if there is an event. “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” (4) The rationale for requirements R2 and R3 contradict with the revisions to the requirements. The rationale states that the TSP was added to allow retirement of IRO-004-2, but the draft removes the TSP from the requirements. Is the intent to keep IRO-004-2 intact? (5) Requirement R3 should be merged with R2. We suggest the following language for consideration, “Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Reliability Coordinator, or shall inform its Reliability Coordinator of its inability to perform because it cannot be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements.” This revision captures the intent of both requirements, is consistent with TOP-001, and reduces the amount of requirements needed. It also reduces unnecessary compliance exposure since only one violation could occur rather than potentially two requirements being violated.
No
(1) We appreciate the drafting team’s consideration of previous comments and subsequent revisions. (2) We recommend changing the term “Special Protection System” to “Remedial Action Scheme” because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirements. (3) Requirement R3 is problematic as written because it implies that sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause “including sub-100 kV facilities needed to make this determination.” If these sub-100 kV facilities are needed for reliability they would be part of the BES exception process and would be covered by the NERC defined term “Facilities.” The FERC NOPR that proposed to remand the TOP/IRO standards was issued on November 21, 2013, which was prior to the BES definition coming into effect on July 1, 2014. This is a significant justification to remove the sub-100 kV language. (4) We recommend verifying that the redlined and clean copies of the draft standard have consistent numbering of the requirements. When R1 was deleted in the redlined version, the other requirements did

not reflect this change. Considering there are over 30 documents to review with this posting, it can be confusing when the requirements do not match.
Yes
No
(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards.
Yes
Yes
(1) We appreciate the drafting team's consideration of previous comments and subsequent revisions.
No
(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 should be revised by removing the words "direct others to act" and stating that the TOP shall issue Operating Instructions to ensure reliability of its TOP Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the TOP shall act or direct others to act by issuing an Operating Instruction, the TOP is limited to only this option. We recommend alternative language for this requirement, "Each TOP shall act or issue Operating Instructions to ensure reliability of its TOP Area." (3) Requirement R1's language of requiring the RC to "ensure reliability" could be used as a zero defect standard

if there is an event. “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” Requirement R2 should be revised by removing the words “direct others to act” and stating that the BA shall issue Operating Instructions to ensure reliability of its BA Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the BA shall act or direct others to act by issuing an Operating Instruction, the BA is limited to only this option. We recommend alternative language for this requirement, “Each BA shall act or issue Operating Instructions to ensure reliability of its BA Area.” (4) Requirement R2’s language of requiring the RC to “ensure reliability” could be used as a zero defect standard if there is an event. “Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area.” (5) Requirements R3, R4, R5 and R6 should be revised to remove the LSE function. (6) For Requirements R10 and R11, we recommend changing the term “Special Protection System” to “Remedial Action Scheme” because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (7) Requirement R10 is also problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause “including sub-100 kV facilities needed to make this determination.” If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term “Facilities.” (8) We appreciate the clarification that Requirement R13 is not intended to require a Transmission Operator to have state estimation and real-time contingency analysis. We recommend revising the RSAW to ensure that auditors will review events to avoid this standard being zero defect. (9) We appreciate the clarification for Requirement R18 that derived limits are SOLs and have removed the GOP from this requirement. (10) Requirements R19 and R20 have a parenthetical (Balancing Authority Area) that should be removed to avoid confusion. If both TOP Area and BA Area are intended, please list both without parentheses.
Yes
No
(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG’s finding’s a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement

R1 is problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause “including sub-100 kV facilities needed to make this determination.” If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term “Facilities.” (3) For Requirements R1 and R2, we recommend changing the term “Special Protection System” to “Remedial Action Scheme” because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (4) Requirement R5 should be revised to remove the LSE function.
No
Yes
No
Individual
Steve Johnson
Western Area Power Administration
No
Western has a concern on the use of the word ensure in R1. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the RC didn’t provide instructions that ensured the reliability of its area. We would suggest changing the last portion of the requirement to ‘…… issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.’
No
Western has a concern on the use of the word ensure in R1 and R2. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the TOP, in R1, or BA, in R2, didn’t provide instructions that ensured the reliability of its area. We would suggest changing the last portion of R1 to ‘…. issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.’ and the last portion of R2 to ‘….issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.’

Individual
Joshua Smith
Oncor Electric Delivery LLC
Yes
No
Proposed Standard IRO-017-1 R3 states: “Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.” Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
No
Proposed Standard TOP-001-3 R9 States: “R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” In response to R9, Oncor recommend s that the requirement to make it mandatory for BA’s and TOP’s to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. R10 as proposed requires each “Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area”. The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a “one size fits all” regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard

TOP-001-3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10 be reworded to provide flexibility for region structure. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to “a continuous duration exceeding its associated IROL Tv”. This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncors recommendation is to keep the existing 30 minute time limit.
Yes
Yes
No
Yes
No
Individual
Scott Langston
City of Tallahassee
Yes
The groups represented by the FRCC Operating Committee support IRO-001-4 revisions in principle, however we seek clarification on the potential interpretations of the term “Operating Instructions” and the potential administrative impact to normal and emergency BES operations needed to demonstrate compliance as stipulated in the Measures.
Yes
However, R5 requires “synchronized information systems”. The FRCC Operating Committee seeks clarification from the drafting team on what constitutes a “synchronized information system”. Consider replacing the word “synchronized” with “coordinated.”
Yes
Yes
Yes
Yes
Yes

The FRCC Operating Committee supports a majority of these proposed requirements. However, the OC does not support the language in new requirement R9 and finds that the mapping from current requirement (TOP-003-1 R3) is incomplete and needs to be addressed by the standard drafting team. The language in the existing TOP-003-1 R3 is more precise and should remain as is. If the SDT is attempting to address the comments from the SW Outage Report Recommendations “TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities,” they should create a separate requirement to reflect the notification for loss of Real-time Assessment capabilities. At a minimum, the requirement should state “telemetering and control equipment”, rather than “telemetering equipment, control equipment”. This will add clarification to the type of equipment being addressed in the requirement. In addition,the word “planned” from M9 was not removed as noted in SDT responses. We also recommend removing the words “interconnected NERC Registered”. The word “impacted” reflects who should be notified. The current mapping of existing TOP-003-1 R3 to TOP-001-3 R9 does not accurately reflect the original intent of TOP-003-1 R3. R19 and R20 have some inconsistencies with referencing TOPs and BAs.
Yes
Yes
Yes
We suggest adding the following clarification to page 2 of the white paper: Remove the terms “Normal (continuous)” from the Pre-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. • Remove the terms “Emergency (short term)” from the Post-Contingency section, example “b”. We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. We also suggest that the paper be reviewed for consistency when using the terms “pre-contingency” and “post-contingency”. Interchanging the use and context causes confusion – i.e. Change the column headers in Table 1, “Pre-Contingency Loading” to “Pre-Contingency Mitigation” and change “Post-Contingency Loading” to “Post Contingency Mitigation”. Another example would be to use “Real-Time flow” instead of “Pre-Contingency Flow”. Also in Table 1, under the ‘Emergency (4hr)” row – “Post Contingency Loading” column change “all” to “available”.
Yes
The comments provided herein are consensus comments of the FRCC Operating Committee entity representatives. Our responses to the above questions in no way intends to convey how individual FRCC OC member entities will vote on the standards being proposed. Thank you for your efforts.
Group
NERC Compliance Policy

Randi Heise
Yes
No
Dominion does not agree with R3, of the “clean version,” as written. We are opposed to the inclusion of the phrase “including sub-100 kV facilities”. We would prefer to modify the requirement to read “Each Reliability Coordinator shall monitor BES Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.” It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. While Dominion acknowledges the SDT’s consideration of its comments relative to inclusion of the phrase ‘sub-100 kV facilities’ it still disagrees with the SDT’s decision to retain it in this requirement for the reasons previously stated. M1 as written, “…and real-time Assessments.”, the word “Real” needs to be capitalized.
No
In R8, Dominion suggests removing the words ‘prevented or’ because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs.
No
While Dominion acknowledges the SDT’s consideration of its comments relative to inclusion of the phrase ‘sub-100 kV facilities’ it still disagrees with the SDT’s decision to retain it in this requirement for the reasons previously stated.
No
In R1.1, Dominion suggests adding “as identified in R1” at the end of the sentence to identify the criteria and process being addressed. Suggested Wording: “R1.1: Criteria and processes for notifications as identified in R1.”
No
In R2, the Dominion suggests changing the word “function” to “roles and responsibilities” to match R1 Suggested Wording: “R2: Each Transmission Operator and Balancing Authority shall perform the functions roles and responsibilities specified in its Reliability Coordinator outage coordination process.”
No
While Dominion acknowledges the SDT’s consideration of its comments relative to inclusion of the phrase ‘sub-100 kV facilities’ it still disagrees with the SDT’s decision to retain it in this requirement for the reasons previously stated. R9 states: “R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.” To be consistent with IRO-008-2

R4, where ‘NERC registered’ has been struck (also struck in TOP-002-4), Dominion suggests ‘NERC registered’ also be struck in R9 in TOP-001-3.
Yes
No
While Dominion acknowledges the SDT’s consideration of its comments relative to inclusion of the phrase ‘sub-100 kV facilities’ it still disagrees with the SDT’s decision to retain it in this requirement for the reasons previously stated.
No
Yes
Dominion encourages the SDT to continue to monitor the status of the proposed definition of Remedial Action Scheme “RAS” as the change in definition will impact this reliability standard as well as other related standards as identified in NERC’s white paper, Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst offers the following comments for consideration. 1. Requirement R3 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. “Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service provider, and Distribution Provider shall inform its Reliability Coordinator [within the time constraints allocated by the Reliability Coordinator in its notification protocol] of its inability to perform an Operating Instruction...”
Yes
Yes
No
ReliabilityFirst offers the following comments for consideration. 1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term “as deemed necessary” in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of “Section 4 – Measurability” of the NERC document titled Acceptance Criteria of a Reliability Standard states “Words and phrases such as “sufficient”, “adequate”, “be ready”, “be prepared”, “consider”, etc. should not be used.” ReliabilityFirst believes the phrase “as deemed necessary” is such a phrase,

which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.
Yes
Yes
No
ReliabilityFirst offers the following comments for consideration. 1. Requirement R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator in its notification protocol] of its inability to perform an Operating Instruction issued by its Transmission Operator..." 2. Requirement R6 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority in its notification protocol] of its inability to perform an Operating Instruction issued by that Balancing Authority."
Yes
No
ReliabilityFirst offers the following comments for consideration. 1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term "as deemed necessary" in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of "Section 4 – Measurability" of the NERC document titled Acceptance Criteria of a Reliability Standard states "Words and phrases such as "sufficient", "adequate", "be ready", "be prepared", "consider", etc. should not be used." ReliabilityFirst believes the phrase "as deemed necessary" is such a phrase, which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.
No
Yes
No

Individual
Joel Wise
Tennessee Valley Authority
Yes
Yes
Yes
Yes
Yes
Yes
No
There should be more than one level of VSL. As currently written there seems to be no allowance for instances where entities may be operating at two different ratings (i.e. temperature-dependent ratings, directional ratings, etc.)for a period of time before the entities coordinate which rating should be used in real-time.
Yes
Yes
No
No
See response for TOP-001-3.
No
Group
BC Hydro
Patricia Robertson
No
The new Requirement has the Reliability Coordinator issuing “Operating Instructions” rather than “Reliability Directives”. The scope of “Operating Instructions” broadens to non-emergency situations. BC Hydro does not support this increase in scope.
No

No Comment, please disregard the selected No.
No
No Comment, please disregard the selected No.
No
The new Requirement has the Reliability Coordinator able to ask for “sub-100 kV’ data if it deems necessary. This is an increase in scope from the data the RC currently asks for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP’s and BA’s follow. The responsibility for coordination should reside with the TOP’s and BA’s, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA’s responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage analysis. An RC driven coordination process does not account for differences and needs of TOP’s and BA’s, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA’s responsibility for assessment of system wide conflicts through study assessment, and development of conflict resolution processes to support operations
No

BC Hydro’s concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of “Operating Instructions” broadens to non-emergency situations. Requirement R3 and R4 have the BA’s complying with TOP’s Operating Instructions. BC Hydro’s concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no “out” clause based on reliability conflicts – such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an “out” clause.
Individual
Gregory Campoli
New York Independent System Operator (NYISO)
No
SDT should consider the use of the word ensure. We suggest revising the phase to, ‘maintain ensure the reliability…’. This term exists in other parts of this group of standards, please consider the comment for all.
No
The SDT should clarify and coordinate the requirements between voice and data equipment requirements and the associated COM-001 and IRO-002-4. The SDT should clarify the COM-001 is restricted to voice communications and the IRO-002-4 R1 is intended to address data. It is also not clear that IRO-002-4 R2 is limited to voice communication and/or data. The NYISO suggests that the voice and data requirements be including only in COM-002 and the ability to approve outages of either system be clarified in IRO-002-4 R2. A possible wording change for R2 could be, ‘ .. authority to approved planned outages and maintenance of its telecommunication and data exchange capabilities (as referenced in R1).
No
The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes may have been based on the requirements to be within IROL’s in 30 minutes. The 30 minute assessment for SOL’s may be over prescriptive as some SOL could be up to 4 hours.
Yes
No

See IRC/SRC Comments
No
See IRC/SRC Comments. The NYISO also would like to suggest the in R1, generation be replaced with generator to be consistent with R1.1.3
No
The NYISO has a concern with the term ensure. We suggest revising the phase to, 'maintain the reliability of it's…' R1/R2: The NYISO does not support the removal of the phrase, ' within it's TOP/BA Area'. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. R7: The NYISO continues to believe the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it from the previous requirements. To address the SDT response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. Our proposed language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency. R13: The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes were based on the requirements to be within IROL's in 30 minutes. The 30 minute assessment for SOL's may be too limiting. R16: The NYISO suggests retaining the work 'own'. This would provide clarity that this in only about the equipment the TOP owns and not other equipment. R19/20: The SDT should clarify the purpose of the bracketed entities (Balancing Authority)? The NYISO believes that R19 should be focused on TOP and R20 should be focused on BA.
Yes
Yes
Yes
The current draft introduces the term 'limiting SOLs'. 'For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the limiting SOLs. Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs. We believe that a better wording would be the 'limiting criteria that results in the identified SOL'.
No
Individual

David Jendras
Ameren
Yes
Yes
Yes
Yes
We are concerned that an entity may have a reportable NERC violation if Contingency Analysis is down for more than 30 minutes.
Yes
Our Daily Analysis supplements the MISO Operational Planning Analysis and although we could rely on MISO, we have chosen to go beyond what is required.
Yes
We are concerned about the change from “Planned Outage Coordination” to “Operational Reliability Data” which as we understand deals with the specification and exchange of data for use in studies for which we find the languages confusing and needing clarification.
No
Group
SPP Standards Review Group
Robert Rhodes
No
R1 – We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Reliability Coordinator takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R1 specifically to those entities identified in Requirements R2 and R3.We recommend the following rewrite: ‘Each Reliability Coordinator shall act, or direct others as identified in Requirements R2 and R3 to act, by issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.' Rationale Box for Requirements R2 & R3 – The Rationale Box for Requirements R2 and R3 does not match the language in the requirements. There is no mention of the Transmission Service Provider in the requirements. It only appears in Measures M2 and M3. The IRO Five

Year Review Team had recommended adding Transmission Service Provider to Requirements R2 and R3 to allow the retirement of IRO-004-2. With the removal of the Transmission Service Provider in Requirements R2 and R3, can the retirement of IRO-004-2 move forward?
No
M1 – Capitalize Real-time in the last line of Measure M1.
No
1.3 Data Retention – Hyphenate 30- and 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Yes
Yes
No
R2/M2 – Make Reliability Coordinator in Requirement R2 and Measure M2 possessive. The requirement should read '…in its Reliability Coordinator's outage coordination process.' R4 – To focus the coordination effort of the Reliability Coordinator on BES issues we recommend modifying the wording of R4 to state '…for identified issues or conflicts on the BES with planned outages…'
No
R1 – We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Transmission Operator takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R1 specifically to those entities identified in Requirements R3 and R4. We recommend the following rewrite: 'Each Transmission Operator shall act, or direct others as identified in Requirements R3 and R4 to act, by issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.' R2 – We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Balancing Authority takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R2 specifically to those entities identified in Requirements R5 and R6. We recommend the following rewrite: 'Each Balancing Authority shall act, or direct others as identified in Requirements R5 and R6 to act, by issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.' R9 – We feel that the use of impacted interconnected entities is too broad for the notification requirement. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Additionally, the term 'NERC registered' in Requirement R9 and Measure M9 should be deleted. This term was deleted in IRO-008-2, Requirement R4 and TOP-002-4, Requirement R3. We recommend rewording the requirement to read: 'Each Balancing Authority and

Transmission Operator shall notify its Reliability Coordinator and known impacted entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities lasting 30 minutes or longer.' Should Requirement R9 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R10 – We have concerns with the existing language in Requirement R10 which when applied in the real-world of today's audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn't model enough of the neighboring TOP's Area? Isn't this really the function of the RC and aren't we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: 'Each Transmission Operator shall monitor 10.1 Facilities within its TOP Area, 10.2 status of Special Protection Systems identified as necessary by the Transmission Operator, 10.3 sub-100 kV facilities identified as necessary by the Transmission Operator, and 10.4 Facilities within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator as necessary to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.' Rationale Box for R14 – The newly inserted sentence in Rationale Box for R14 doesn't completely present the overall picture of the Operating Plan as contained in the Associated Documents at the back of the standard. We propose an additional sentence, as indicated below, be included in the Rationale Box. '…These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments (OPA) required per proposed TOP-002-4 or other assessments. The Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). The intent is not to have a…' R18 – Should Requirement R18 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R19 – Delete the parenthetical Balancing Authority in Requirement R19. R20 – Delete Transmission Operator and the parentheses around Balancing Authority in Requirement R20.
No
R4 – We suggest that load forecast uncertainty and resource uncertainty be added to the list of Parts for Requirement R4. 1.3 Data Retention – Hyphenate 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Yes
Yes
Hyphenate 24-hour in the 8th line under 1. on Page 1. First full paragraph on Page 3, we suggest the following rewrite for the last sentence in that paragraph. 'Conversely, if an area is not at risk of instability, no Facilities are approaching their thermal Facility Ratings but the

area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the limiting SOLs.' We also suggest deleting the 1st sentence in the following paragraph on Page 3. The paragraph flows better without it. We further suggest the following rewording in what would then be the 2nd sentence in the paragraph. 'How an entity remains within these SOLs can vary depending on the operating practices and planning strategies employed by that entity.' In 4. Voltage Stability Limits, replace the 2nd sentence with the following: 'Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met.'
No
IRO-008-2 R4 – Change the Severe VSL for new Requirement R4 (old R5) to read '…more than three…' or '…four or more…' in lieu of '…three or more…'. The High VSL already uses three. IRO-014-3 R3 – The lead-in for the VSLs for Requirement R3 refers to Requirement R5. This reference should be to Requirement R3. R7 – Change the Severe VSL for Requirement R7 to read '…Coordinator had implemented…' and '…or would have violated safety…'. IRO-017-1 R2 – Make Reliability Coordinator possessive in the Severe VSL for Requirement R2. TOP-001-3 R8 – Delete 'other' in the VSLs for Requirement R8 referring to '…other known impacted Balancing Authorities…' and '…other Balancing Authorities…'. The use of 'other' only applies to references to Transmission Operator. Also in the VSLs for R8, change 'less' to 'greater' such that the Lower VSL would read: 'The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the affected known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.' (This particular change applies to all VSLs in R8, R9, R19 and R20 as well as the VSLs for IRO-002-4, R1; IRO-008-2, R3, R5, R6; IRO-010-2, R2; TOP-002-4, R3, R5; TOP-003-3, R3, R4.) R9 – Delete the term 'NERC registered' in the VSLs for Requirement R9. (See comment in Question 7 above. R13 – Change the Severe VSL for Requirement R13 to read '…more than three…' or '…four or more…' in lieu of '…three or more…'. The High VSL already uses three. R19/R20 – Replace 'applicable' with 'identified' in the VSLs for Requirements R19 and R20. The use of 'identified' parallels the language in the requirements. TOP-002-4 R3 – Replace 'NERC' with 'entities' in the High and Severe VSLs for Requirement R3.
Yes
The definition of Special Protection System (SPS) is being revised to Remedial Action Scheme (RAS) yet this package of standards continues to use SPS. Other active drafting teams, particularly the Relay Loadability: Stable Power Swings and the Protective System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) teams, are using the new RAS definition in their work. What process will be used to make the transition to RAS when the new definition is approved? Similarly, Load-Serving Entity will soon be eliminated as a registered function at NERC. How will this change be reflected in the standards? We recommend that all changes we have proposed for the standards be reflected in the RSAWs as well.
Group

Duke Energy
Michael Lowman
No
R1: Duke Energy suggests re-writing R1 as follows: “Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure the reliability of its Reliability Coordinator Area.” As written, we believe that every communication involving an RC could be considered an Operating Instruction. For example, If a BA/TOP informs the RC of a loss of unit/tripping of equipment and the measures taken to mitigate the situation. Would an RC be required to give Operating Instructions back to the BA/TOP stemming from an informational conversation? We feel the revision adds clarity that the RC will issue Operating Instructions only when they believe it is warranted. R2: No comments M2: All instances of Transmission Service Provider should be removed from this measure. R3: No comments
No
R1: Duke Energy suggests the following revision: “Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.” We believe adding “its BA and TOP” narrows the scope of data sharing required by the RC. We believe the intent should be to ensure the RC has data sharing capabilities with the BAs and TOPs in its RC area and with other entities that the RC believes are needed for performing Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. R2: No comment R3: Duke Energy suggests the following rewording: “Each Reliability Coordinator shall monitor identified Facilities, status of Special Protection Systems, and sub-100 kV facilities necessary to identify any System Operating Limit exceedances, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." We believe this rewording provides more clarity on the intent of this requirement. R4: Duke Energy suggest the following language: “Each Reliability Coordinator shall have Energy Management Systems and SCADA data that provides information utilized by the Reliability Coordinator’s System Operator over a redundant infrastructure.” We feel the language “as written” is too broad. We feel this revision helps remove the perceived vagueness when referring to “monitoring systems”. Also, in regards to “redundant infrastructure”, we ask the SDT the following question: If an entity has redundant capability of its EMS system and one leg of that system is rendered unavailable during a planned or unplanned outage, is the RC non-compliant? In this example, the RC will not be on a redundant system due to the outage. We have concerns that the language as written in the standard would render the RC non-compliant.
No
R1: No Comment R2: No Comment R3: No Comment R4: No Comment R5: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an RC’s Energy Management

System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R6: We believe the incorrect requirement was referenced in R6. The phrase should be as follows : “when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.” Please change the reference of “R6” with “R5” as seen in the example above. R8: Duke Energy suggests the following revision: “Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated.” We suggest removing “prevented” because the prevention of SOL/IROL exceedances will be difficult to prove and would not typically be communicated to BAs and TOPs. The communication activities should be restricted to communications of activities to mitigate a potential SOL/IROL exceedance and not the prevention.
No
Duke Energy does not disagree that the types of data exchanges described in this proposed IRO-010 are necessary. However, we believe that these data exchanges currently take place within the context of various existing ERO Requirements and/or various existing agreements between the Applicable Entities. Therefore we do not believe there is a need to codify these requirements in another ERO Standard. As written, this Standard simply creates additional administrative burden on the industry while providing no incremental reliability benefit. As written, Duke Energy believes this Standard would simply become a candidate for a future Paragraph 81 submittal.
No
R1.1 – Duke Energy suggests the following language: “Criteria and processes for notifications as identified in R1.” This provides the clarity on the specific notifications that are required with adjacent RC(s) as defined in R1. R2: No Comment R3: No Comment R4: No comment R5: Duke Energy suggests the following revision: “Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.” We believe “identifies” is the appropriate wording. R6: “Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.” We believe “identifies” is the appropriate wording.
No
While we are open to the suggestions made by the SDT, if the scope of RC is going to be expanded, we believe revisions to the Function Model need to occur first and then distributed to the industry for review and approval. The Functional Model is the foundation for the development of Reliability Standards used by Standard Drafting Teams. As indicated

above, these revisions to the Functional Model need to occur first before a substantial change in roles and responsibilities of Functional Entities take place within the standards. R1: No comments R2: Duke Energy suggests the following revision: “Each Transmission Operator and Balancing Authority shall perform the roles and reporting responsibilities specified in its Reliability Coordinator outage coordination process.” The use of “roles and reporting responsibilities” in the place of “functions” better aligns with the language used in R1.1 of the proposed standard. R3: No comments R4: Duke Energy suggests the following revision: “Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.” We believe “identified issues or conflicts on the BES” better aligns with the intent of this requirement and adds clarity that the RC, PC , and TP will jointly develop solutions for conflicts on the BES.
No
R1: Duke Energy suggests re-writing R1 as follows: “Each TOP shall act or issue Operating Instructions to entities, as necessary, within its TOP Area to ensure the reliability of its TOP Area.” We believe “within its TOP Area” is necessary within the context of the standard. Requirements R3 and R4 appear to imply that Operating Instructions from a TOP are within the bounds of the TOP area only. However, by removing this language, it is our view that the TOP could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R2: Duke Energy suggests re-writing R2 as follows: “Each BA shall act or issue Operating Instructions to entities , as necessary, within its BA Area, as necessary, to ensure the reliability of its BA Area.” We believe “within its BA Area” is necessary within the context of the standard. Requirements R5 and R6 appear to imply that Operating Instructions from a BA are within the bounds of the BA area only. However, by removing this language, it is our view that the BA could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R3-R6: No Comments R7: While Duke Energy believes that this is a great operational expectation or operating practice for a TOP, we believe that the requirement “as written” is unmeasurable. We believe it will be difficult for an auditor to measure how a TOP verified that another TOP implemented “its emergency procedures”. The term “emergency procedures” is too vague and subject to interpretation. For example, at what point in another TOP’s emergency procedures should a TOP provide assistance? Based on this language, we suggest removing R7 from this standard or adding this to a guidance document to promote operational excellence within the industry. R8: Duke Energy suggests re-writing R8 as follows: “Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities and other impacted Transmission Operators, of its actual or expected operations that result in, or could result in a known Emergency.” R9-R12: No Comments R13: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an TOP’s Energy Management System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R14-R20: No Comments

No
R1: Duke Energy suggests re-writing R1 as follows: “Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any identified System Operating Limits (SOLs).” We believe the addition of “identified” adds additional clarity and conforms to the language in FAC-011. R2: Duke Energy requests clarification on whether a process for each SOL exceedance identified in the Operational Planning Analysis is necessary or is one document that address any and all exceedances of SOL(s) is acceptable? R3: Duke Energy believes “impacted” is not needed in the context of the requirement and suggests removal. R4: No Comment R5: Duke Energy believes “impacted” is not needed in the context of the requirement and suggests removal. R6/R7: Duke Energy suggests the following for R6: ”Each Transmission Operator shall provide the results of its Operating Planning Analysis for next-day operations identified in Requirement R2 to its Reliability Coordinator.” We also believe that R6 and R7 goes beyond the scope of Recommendation 1 of the SW Outage Report. The report indicates that TOPs should share the results with neighboring TOPs and RCs, and not necessarily the Operating Plan itself. In addition, the BA is not cited in Recommendation 1 of the SW Outage Report as having to do the same type of analysis.
No
Duke Energy asks the SDT to consider adding a mechanism to allow a recipient of a request to challenge the requestor if a reliability related need cannot be established. For example, should a BA wanting to know the ACE of every BA within the Eastern Interconnection be allowed to get this information if there is not a reliability related need to have the information?
Yes
Duke Energy agrees with the SOL Performance Summary described in Figure 1. We believe that Figure 1 adequately describes the intent on treatment of SOL(s), more so than the text of the White Paper itself. We suggest that the SDT revise the text in the White Paper to better align with the SOL Performance Summary in Figure 1.
No
Duke Energy does not necessarily disagree with the VRF(s) for IRO-017. However, we are seeking clarification for the increases in VRF from a “lower” in the first posting to a “medium” on this posting.
No
Group
IRC Standards Review Committee
Greg Campoli
Yes
Yes

No
a. R6 and all of its VSL: The reference to “as identified in identified in Requirement R6” should be revised to “as identified in identified in Requirement R5”. b. We wish to reiterate our previous comment on the inconsistent language used between Requirement R6 (was R8 but misquoted in our previous comment as R6) and the LOWER VSL for R6 in which the word “Emergency” is used but the condition is not specified in R6. R6 stipulates that: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. However, the LOWER VSL for R6 indicates that: The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan “when the Emergency identified in Requirement R6 was prevented or mitigated.” Please revise VSL to read “when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated” as opposed to “Emergency” for consistency. c. The language between R4 and its VSL is inconsistent. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC to “perform” to “ensure that” a Real-time Assessment is performed. However, the VSL still assesses the condition that the RC did not “perform” as opposed to did not “ensure that” the Real-time Assessment was performed. Please revise as appropriate.
Yes
No
a. We generally agree with the changes made to IRO-014-3. However, the replacement of “other” with “adjacent” may leave a reliability gap. For example, the notification of Transmission Loading Relief invasion may require “notification or coordination of actions” by, and can have an impact on, RCs other than just the adjacent RCs. Since the words “may impact” already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word “other” into R1. b. We do not have a preference, but ask the SDT to review the use of the phrase “Wide Area” in IRO-008-2 (and other IRO standards) and the phrase “Reliability Coordinator Area” in IRO-014-3. If these phrases are expected or interpreted to be synonymous, we suggest to use one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion. c. Retention Period: We are unable to find the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors.
No

During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
No
We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
Yes
Yes
No
During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT's response indicates that "it has revised the whitepaper to include "as necessary and appropriate". However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that "All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan." We speculate that the insertion of "as necessary and appropriate" to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, "However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating)." We urge the SDT to reassess whether or not the "as necessary and

appropriate” should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.
Yes
Yes
During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT’s response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any “proven reliable power system limits” as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a “white paper” status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary action to “restore operations to respect proven reliable power system limits within 30 minutes” when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. Please advise.
Group

Colorado Springs Utilities
Kaleb Brimhall
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following were the comments that we had in addition to SPP's comments. CSU references our previous comments again as we do not feel they were addressed correctly. 1. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 2. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. The response by the SDT referenced other requirements that require notification in other standards stating that the time requirements are covered under those requirements. The requirements referenced by the SDT do require notification at the time of an actual SOL or IROL etc. IRO-001-4 is the pre-contingency analysis that needs to be communicated. We do not feel that the requirements referenced by the SDT cover the pre-contingency analysis required to be communicated by IRO-001-4.
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
Yes
No Comments
Yes
No Comments
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following are our additional comments above and beyond what SPP's comments are. R13 - Would a tool such as a state estimator or RTCA be required to meet the Real-time Assessment definition or can it be done without “real-time” tools? Your response to our previous comments allude to the fact that all entities are currently using or contracting for such “real time” tools which is not universally true. Additional

implementation period is needed and thus requested due to the time needed for budgeting and implementation of “real time” tools.
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
Yes
Yes
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
No
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
Yes
We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
There are still mentions of the "Transmission Service Provider" even though it has been removed as an applicable entity. It is mentioned twice in Measure M2 and once again under the compliance section "1.3 Data Retention." All references to the Transmission Service Provider should be removed.
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
No
Yes
No
Individual
Michael Moltane
ITC
Yes
ITC has concerns with the definitions of “Operational Planning Analysis” and “Real-time Assessment”, as they are used throughout the IRO and TOP standards. “Operational Planning Analysis” definitions states: The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations.” “Real-Time Assessment” definition states: The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. ITC is appreciative of the addition of the word “applicable” in the two definitions noted above, to provide more flexibility in selection the input. However, while the addition of the word “applicable” was an improvement, we are left with the issue of who determines “applicability” of the inputs. Lack of specificity in this regard will lead to confusion as to

whether the audit team or the entity will determine input. To clear this up, ITC suggests the addition of the following language to both definitions: “The evaluation [assessment] shall reflect inputs determined applicable by the entity such as …”. An example of how this would be beneficial would be regarding the input of “known Protection System and Special Protection System status or degradation”. This input can be utilized in the dynamic analysis conducted outside the next day or real time horizon. The revised wording would make it clear that the entity can exclude this input from it next day or real time studies.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
See VSL comments in response to question #11 below.
Yes
R4 begins with ‘Each Reliability Coordinator shall monitor Facilities...’ Southern suggest that the words, “Bulk Electric System” be added to R4 so that it reads ‘Each Reliability Coordinator shall monitor “Bulk Electric System Facilities”, consistent with the verbiage in IRO-003-2 Requirement 1. Measure 4 should also be changed accordingly. R4 - Southern suggest that utilization of the words, “as necessary” makes the requirement confusing and proposes the below verbiage to add clarity: ‘Each Reliability Coordinator shall monitor “Bulk Electric System Facilities”, the status of Special Protection Systems, and sub-100 kV facilities identified by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, “as being necessary to determine” any System Operating Limit (SOL) exceedances within its Reliability Coordinator Area.’ Changes would apply to Measure 4 as well.
No
R4 – It is not clear why the SDT removed the qualifier “NERC registered”. Southern recommends adding “NERC registered” back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. In addition, Southern noted that the SDT responded with the following comment in consideration of comments received for R4. “Impacted goes beyond the concept of those entities that have an active role to play in the Operating Plan. It also includes those entities which may not have an active role to play in the plan but are still impacted by the given operating condition. For example, an entity may have Load impacted by a given situation and the only available option that entity may have is to shed that Load. But if the plan doesn’t call for that entity to shed the Load, then the entity doesn’t have an active role in the plan but is still impacted by the situation and therefore is deserving of notification.” It is very unclear on what expectation the SDT is suggesting in this comment. If the RC conducts a next day study and identifies potential issues, the RC will develop a plan to resolve the issue. This plan will be communicated to the NERC registered entity that is responsible for implementing the plan. The example provided by the SDT is unclear and

confusing in that it introduces an entity that was never part of the plan to resolve the issue. If this entity was never part of the plan, why would or should the RC notify such entity? R8 – Southern suggests modifying R8 as follows (include "actual") to require notification in the event of an actual SOL or IROL exceedance within the RC area, but not require notification in the case where there was a possible SOL/IROL exceedance, but system conditions changed that cause the potential issue to subside. Southern believes that requiring notification for the latter is a good utility practice, but does not maintain or enhance reliability as it is nothing more than a notification that "nothing is required any longer for what could have been" "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. [Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations] Southern also recommends moving the word "known" in the definition of Operational Planning Analysis to the beginning of the second sentence to reflect that the evaluation shall reflect applicable "known" inputs. The "known" should apply to each of the inputs and not just Protection Systems and SPS status and degradation. The Operational Planning Analysis should reflect what the TOP knows at the time the evaluation is conducted. TOPs continue to update the studies as updated or "known" information becomes available. See suggested revision below. Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable known inputs including, but not limited to, load forecasts; generation output levels; Interchange; Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Yes
No
Southern agrees with the compliance assessment approach and note to the auditor in the RSAW and recommends that the SDT incorporate these concepts into the standard itself. The RSAW clearly recognizes that events / Emergencies have varying levels of significance. Southern continues to think the current definition of "Emergency" is too broad and is misused in standards development. This standard, and in particular requirements to notify neighboring RCs, should be focused more on issues that can truly impact them, not any situation that could be interpreted as an "Emergency" as it is currently defined. Southern recommends the SDT replace Emergency with Adverse Reliability Impact as it was before. If the SDT does not accept this recommendation, the SDT should consider modifying the requirements or even the definition of "Emergency" to incorporate the concept that an "Emergency" is an operating condition which has not been studied or for which no mitigation plan has previously been developed. For example, having a contingency occur

which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance, is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible.
Yes
Southern believes that Requirement 4 should provide clear guidance that the Planning Coordinator and Transmission Planner are responsible for initiating the review of solutions with their Reliability Coordinator and additional language should be added to clarify that the joint discussions should only be focused on issues that may impact the Operations Planning Horizon. Southern proposes the following revision to the requirement: "Each Planning Coordinator and Transmission Planner shall coordinate with its respective Reliability Coordinator to jointly develop solutions for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, which may ultimately impact the Operations Planning Horizon."
No
R1 and R2 - Southern understands other commenter's concerns about BAs, GOPs, DPs, and LSEs not falling into a Transmission Operator's TOP Area, but Southern disagrees with the approach taken by the SDT to address these concerns. Rather than removing "within its TOP Area" in R1 and "within its BA Area" in R2, the requirement should spell out the entities to link to R4 and R5. Suggested change as follows: R1 - Each Transmission Operator shall act, or direct its Balancing Authorities, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R2 - Each Balancing Authority shall act, or direct its Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure reliability within its Balancing Authority Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R10 begins with 'Each Transmission Operator shall monitor Facilities...' Southern suggest that the words, "Bulk Electric System" be added to R10 so that it reads 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", consistent with the verbiage in IRO-003-2 Requirement 1. Measure 10 should also be changed accordingly. R10 - Southern suggest that utilization of the words, "as necessary" makes the requirement confusing and proposes the below verbiage to add clarity: 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", the status of Special Protection Systems, and sub-100 kV facilities identified by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas, "as being necessary to determine" any System Operating Limit (SOL) exceedances within its Transmission Operator Area.' Measure 10 should also be

changed accordingly. R15 - Southern appreciates the SDT's consideration of Southern's comments but disagrees that the Requirement as currently drafted, does not reflect "past tense" with respect to actions taken. Southern suggest that the SDT reword the Requirement for clarification purposes: 'Each Transmission Operator shall inform its Reliability Coordinator of its actions taken to return the system to within limits when a SOL has been exceeded.'
No
R3 - It is not clear why the SDT removed the qualifier "NERC registered". Southern recommends adding "NERC registered" back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. R5 – See comment regarding removal of "NERC Registered" for R3. Also, in the SDT's consideration of our previous comments, the SDT states they do not believe R5 requires notification. Given R5 clearly states that the BA shall notify impacted entities, it is not clear what the SDT's expectation / interpretation of this requirement is. Southern suggests modifying the requirement to incorporate the concept that notification from the BA is only required to entities where the BA is requesting an action that is different than what the entity provided to the BA. For example, if a GOP provided their expected generation resource commitment and dispatch to the BA, the BA reviews the information and determines that this particular GOP needed to commit additional units to provide more regulation, frequency response, etc., then the BA should notify this GOP. If another GOP provided data and the BA did not have any suggested changes, then there should not be a notification requirement. Suggested changes are as follows: "Each Balancing Authority shall notify NERC registered entities identified in the Operating Plan(s) cited in Requirement R4 when the BA is requesting the entity to take an action that is different from the last submitted plan the entity originally provided to the BA."
Yes
Yes
As currently presented, the example Operating Plan in Table 1 on page 8 of the SOL Exceedance White Paper is confusing. It is actually a pretty good attempt to capture in table form the concepts described in the document text related to the time limit is exceeded versus pre-/post- contingency. However, it uses terms such as "non-cost" and "off-cost" which are not standard industry terms and which are not used elsewhere in the document. The SDT should consider removing these terms and using more standard terms, such as re-dispatch reconfiguration, etc. as appropriate. In addition, the "Legend" shown is confusing and does not help support the example.
No
Southern disagrees that any violation of IRO-001-4 requirements constitutes a Severe VSL. The RSAW suggests that auditors are to use the NERC EAP process (i.e. reviewing entity's Category 2 or higher events) in their compliance assessment. Southern agrees with this approach and suggest the SDT adopt this thought process in the VSLs. For example, a

Severe VSL would be a case where there was non-compliance for a Category 4 or 5 event, a High VSL would be for Category 3 events, and so on. This method should be used as not all events where Operating Instructions are issued, are equal.
No
Individual
Ayesha Sabouba
Hydro One
Yes
Agree with same comments as NPCC-RSC
No
Agree with same comments made by NPCC-RSC
Yes
Agree with same comments made by NPCC-RSC
Yes
Agree with same comments made by NPCC-RSC
Yes
Agree with same comments made by NPCC-RSC
Yes
Agree with same comments made by NPCC-RSC
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Agree with comments by NPCC-RSC
Yes
Agree with comments by NPCC-RSC
Yes
Agree with comments by NPCC-RSC
Yes
Agree with comments from NPCC-RSC
Yes
Agree with comments by NPCC-RSC
No
Individual
Bill Temple
Northeast Utilities
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Yes
No
Individual
Jason Snodgrass
Georgia Transmission Corporation
No
(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) The current proposal for R2 as written could overly expose the DP to excess and double jeopardy compliance obligations for routine switching operations DPs perform on a daily basis which does not affect the reliability of the BES. Daily switching which require Operating Instructions could include scheduled outages for maintenance items and new construction. The functional model clearly states that RCs "…Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators". Based on this, one could assume the Operating Instruction issued by an RC to a DP would be limited to a load shedding scenario and not daily switching routines mentioned above. However, this arrangement becomes less clear when the issuer of the Operating Instruction has multiple registrations with NERC as the RC, BA, and TOP; and when the recipient of the operating instruction is registered with NERC as a DP, TO, and TSP. Under such exchange, a single Operating Instruction issued from such an entity is technically an Operating Instruction from the RC, BA, and TOP; the recipient of this

single Operating Instruction also applies to each of their registration type being a DP, TO, and TSP. To the auditor, this single Operating Instruction could be the same piece of evidence for multiple requirements across multiple Standards such as IRO-001 and TOP-001. GTC believes the RC to DP interaction (with the RCs wide area view) is limited to Emergency scenarios which warrant a separate requirement for clarification of such exchange. A separate requirement for the DP is also justified and helps the ambiguity surrounding Real Time vs Ahead of Time activities within scope of the RC. The RC could issue Operating Instructions to the TOP, BA, GOP and IA for both Real Time and Ahead of Time, but GTC believes the DP is limited to Real Time horizon associated with “load shed” only in order for the RC to ensure the reliability of its Reliability Coordinator Area. A standalone requirement would correct the ambiguity expressed above and would more accurately capture the scenario of when the RC would be issuing Operating Instructions to the DP rather than BA, TOP, GOP, etc. Again, GTC’s goal is for this requirement not to overlap on the daily switching routines performed by the DP which require Operating Instructions such as scheduled outages for maintenance items and new construction when the issuing entity has both registrations of RC and TOP. GTC proposes the following standalone requirement for the DP: “Each Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions associated with load shed unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.” Alternately, GTC would accept “Each Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions during an Emergency unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.”
No
GTC supports comments made by GSOC for IRO-002-4
No
GTC supports comments made by GSOC for IRO-008-2
No
(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG’s finding’s a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity

through the BES exceptions process. Asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards.
No
GTC supports GSOC's comments for IRO-014-3
No
(1) GTC disagrees that outages are planned for the near term planning horizon (years 1 – 5). Outages are planned and scheduled within the operational planning horizon (up to year 1). The Planning Assessment only covers the near term and the long term planning horizons; it does not cover the operational planning horizon. Furthermore, the RC model can only include the current system that has been built and deals with real time parameters. They cannot grant outages on proposed planning solutions. The Planning Assessment does not provide any useful information for scheduling outages in the operations horizon. An outage request for construction of new stations, lines, or facility upgrades is what is required so that the RC can run a real-time assessment and grant approval for outages. R1 and R2 adequately cover the process to grant outages as they are requested, and sufficiently cover the purpose of this standard. GTC believes R3 and R4 are not necessary for outage coordination in the operations horizon and should be eliminated from this Standard. Additionally, the purpose statement should remove reference to Near-Term Transmission Planning Horizon.
No
(1) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which are not performed to “ensure the reliability” of the BES, such as scheduled outages for maintenance items and new construction, etc. The DP and LSE implement Operating Instructions on non-BES equipment on a routine basis, but the implementation of Operating Instructions on BES or non-BES equipment “to ensure the reliability of the BES” is not very routine. Based on the stated purpose of the standard, GTC believes this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. We believe that the use of the NERC term “Emergency” would properly capture the stated intent of this standard. GTC proposes the language “[during an Emergency]” be added after “....shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] “. Based on the stated purpose (which we believe is adequately captured by the use of the term “Emergency”), at a minimum, Operating Instructions issued to ensure the reliability of the BES should be the only Operating Instructions covered by this standard (as was done in R1 and R2). As is currently written Operating Instructions for scheduled outages associated with maintenance items and new construction will also be in scope which conflicts with the stated purpose of this standard. (2) Based on the functional model, the TOP is responsible for the Real-time operating reliability of its Area and has the authority to ensure that its TOP Area operates reliably. Thus, it is clear to us that part of the job of the TOP and/or BA to ensure that the Operating Instructions they issue are performed. Recipient entities such as the DP would rely on the TOP or BAs voice recordings

as evidence which is duplicative to what the TOP or BA is already collecting. We would suggest the following: R3: Each Transmission Operator is to verify each Operating Instruction it issues as a part of R1 is completed, unless informed that such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. R4: Each Balancing Authority is to verify each Operating Instruction it issues as a part of R2 is completed, unless informed that such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. An additional benefit to writing the requirements in this manner is a substantial reduction in redundant administrative record-keeping. TOPs and BAs will already be collecting such information as a part of R1 and R2, so requirements along the lines of those proposed above would provide the additional benefit of preventing duplication of records between multiple entities, keeping records of these Operating Instructions performed with the TOP and BA.
No
GTC supports GSOC's comments
No
(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 is problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100 kV facilities are needed for reliability they would be included in the BES per the BES exceptions process and would be covered by the NERC defined term "Facilities." (3) For Requirements R1 and R2, we recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (4) Requirement R5 should be revised to remove the LSE function.
No
No
GTC will delay providing feedback to VRSs VSLs per revisions to the aforementioned requirements during the following ballot period.
No

Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
PJM is submitting affirmative ballots for all the standards. The revisions made to IRO-002-4 and IRO-008-2 addressed PJM's concerns with the previous drafts of these standards.
Group
Peak Reliability
Jared Shakespeare
Yes
Yes
Yes
R1 as written requires the RC to perform an OPA to assess whether planned operations will exceed SOLs and IROLs in its Wide Area. NERC defines Wide Area as “The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of

Interconnected Reliability Operating Limits". According to this NERC definition, the Wide Area does not include actual Facilities outside the RC Area, but rather includes flow and status information from adjacent RC Areas for the purposes of IROL calculation (whether the IROL is in the RC Area, in the adjacent RC Area, or spanning across multiple RC Areas). It brings in information from outside the RC Area for IROL calculation – it does not bring in additional Facilities outside the RC Area for general monitoring. Therefore, requiring an OPA to assess SOL and IROL exceedances in a Wide Area actually doesn't make sense, given the fact that the Wide Area does not include actual Facilities outside the RC Area, but rather information from outside the RC Area. Given the NERC definition of Wide Area, the requirement can only make sense if it requires the OPA to assess whether planned operations in its Wide Area (i.e., flows and statuses outside its RC Area for the purposes of IROL calculation) is expected to exceed any of its SOLs and IROLs. Peak believes that the standard should be rephrased to state, "Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations within its Wide Area for the next-day will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs)." With this language change, the flow and status information from the Wide Area are included in the RC's OPA to determine SOL and IROL exceedances appropriately (including IROLs within the RC Area as well as IROLs that span multiple RC Areas). This language change will also bring consistency with its companion requirement TOP-002-4 R1, which states, "Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." Peak believes this language change accurately reflects the NERC definition of Wide Area and ensures SOLs and IROLs are addressed appropriately to ensure reliability across the board. R5: It should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.
Yes
IRO-010-2 R1 states, "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." The concern with this language is the limiting nature of the scope of the data specification. The OPA is limited to data for next-day operations. R1 should not confine the RC's data specification to data for its OPA and RTA only, but rather should facilitate the RC to obtain the data it needs to perform its RC functions overall. With the current language, a TOP or BA may be able to claim that they have no compliance obligation to provide the RC with data it needs to perform its reliability functions. Peak recommends that R1 be rewritten to state: "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its reliability functions." R2 should be updated similarly.
Yes
The new R4, R5, and R6 should also include "actual or expected Emergency" like R3.

Yes
No
There still needs to be clarity about conflicting Operating Instructions. For example, if TOP 1 gives and Operating Instruction to TOP 2 and then TOP 3 gives an Operating Instruction to TOP 2, which one trumps? The same would be true for BAs. This creates potential conflicts for TOPs, BAs, and RCs. "within its … Area" should not have been removed. R9: Why restrict to NERC registered entities when this term was removed from other requirements throughout the IRO/TOP revisions? R13: Should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.
Yes
Yes
Yes
The SOL Whitepaper directly addresses the confusion, debates, and misconceptions around the SOL concept that is so prevalent in the industry. Many thanks to the SDT for issuing the much needed SOL Whitepaper. Peak believes this paper will not only bring clarity and resolution to confusing and even contentious issues related to SOL establishment and exceedance, but will also result in improved reliability.
Yes
TOP-001-3 R13: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted …3 times….Severe VSL TO RTA not conducted 3 or more times…) IRO-008-2 R4: The VSL removed the first occurrence of the term “NERC registered” entity but left the term in the second half of the VSL. IRO-008-2 R5: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted …3 times….Severe VSL TO RTA not conducted 3 or more times…)
No
Individual
Glenn Pressler
CPS Energy
No
Yes
Yes
No

R1.2 in general, support CenterPoint Energy comments (heard through NSRS).
Yes
No
Propose the following: Strike “Near-Term Transmission Planning Horizon” from Purpose; TPL-001-4 R1.1.1 already requires the model to represent known outages of generation or Transmission Facilities with a duration of at least six months. If outages with a duration of less than six months are required, then this should be a revision to the TPL standard. Strike “4.5. Transmission Planner” from Applicability: All requirements related to the Transmission Planner are either redundant to the TPL-001-4 standard or should be incorporated therein. Strike all of requirement R3: This requirement is redundant to the TPL-001 R8 requirement, since for ERCOT, the Planning Coordinator is the same as the Reliability Coordinator. If it cannot be stricken, then there should be a qualifier that states “this requirement only applies if the Planning Coordinator is NOT the same as the Reliability Coordinator”. Otherwise, the Transmission Planner in the ERCOT system is subject to double-jeopardy regarding this standard and the TPL-001 standard. Strike all of requirement R4: If it is required that the Planning Coordinator, Transmission Planner and Reliability Coordinator all have to work together to jointly develop solutions for planned outages less than 6 months in duration, then this should be reflected in the TPL-001 standard. In general, introducing standards that impose requirements on the Planning Assessment should all be incorporated in the TPL-001 standard as opposed to several disjointed standards, which creates confusion and possible redundant and double-jeopardy situations. Regarding R3 & R4, in general Paragraph 90 perspective is misinterprete & should be limited to next day (not up to 1-year).
No
R1, in general, change to only require TOP to have the authority to act, or direct others to act, R10, in general, regarding monitoring Facilityies reaching into a neighboring TOP area needs clarifying...best to delete neighboring areas wording.
Yes
No
see comments for IRO-010-2
No
No
Individual
Scott Berry
Indiana Municipal Power Agency

No
The use of a documented specification for the data needed by the Reliability Coordinator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instances where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Reliability Coordinator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means Generator Operators in this RC area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.
No
IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow. What happen to results-based standards? Just keeping the telephone logs in many instances will not be enough and it will require much more documented evidence to show that an entity followed the TOP’s Operating Instructions. If a Generator Operator is asked to change MW/VAR output or asked to maintain the same output numerous times in a day by its Transmission Operator, it will have to keep evidence to show that it carried out every single Operating Instruction throughout the entire day. Does this mean keeping track of the output of the Generator for the day and giving the entire log to the auditor to show the Generator Operator carried out each Operating Instruction?
No
The use of a documented specification for the data needed by the Transmission Operator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instance where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Transmission Operator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means that Generator Operators in this TOP area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.

No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
No
The implications of removing the term NERC Registered from R4 are unclear because a Planning Coordinator may not be able to rely on information provided by unregistered entities. If the RC in IRO-008-2 M3 creates an Operating plan that includes non-registered Entities (TOP-002-4 R4 clearly shows that NERC thinks that non-registered entities WILL be included in some Operating Plans), the TOP responsibility of TOP-002-4 will only pertain to the NERC registered entities. This creates a serious potential reliability “gap” that must be addressed before this draft can be evaluated.
Yes
Yes
No
PacifiCorp cannot agree to the proposed new standard without having an understanding of the “Reliability Coordinator outage coordination process”. Additionally, PacifiCorp needs to understand how the Reliability Coordinator will resolve identified outage conflicts. PacifiCorp cannot support the proposed change of the Violation Risk Factor in R3 from Low to Medium.
No
PacifiCorp needs clarification concerning how R16 works in tandem with the Reliability Coordinator outage process noted in IRO-017-1. Additionally, PacifiCorp questions whether we have the ability to compel a non-NERC Registered Entity to provide data in order to maintain reliability in the Transmission Operator Area. Also, inclusion of the Near-term Planning Horizon (which is 1 – 5 years) into the future isn’t appropriate. This should be addressed in a revised TPL standard. Does this mean that Planning must coordinate all proposed 6 month (see TPL-001-4 R1 effective on 1/1/2015) or longer outages with the DMCC up to 5 years into the future every X days, months, or annually?
No
: PacifiCorp cannot support the standard as proposed with the removal of the term NERC Registered from R3 and R5 given that the obligation to notify non-NERC Registered entities

introduces an element of uncertainty into our notification obligations. Also, does next day require DMCC changes for Saturdays and Sundays? At least Operating Plan Analysis seems to allow for next-day analysis. Is the intention to mandate 24/7 rotating staff in control rooms?
Yes
No
No
PacifiCorp cannot support the proposed change of the Violation Risk Factor in IRO-017-1 R3 from Low to Medium with inadequate justification for the change.
No
TOP-001-3 exceeds the NOPR by requiring Protection Systems in addition to Special Protection Systems. The tools used to produce Real-time Assessments using Real-time data are not dynamic stability assessment tools, and do not inherently understand the status of all “Protection Systems”, degradations, or identified phase angles and equipment limitations. Note the definition references “Protection System and Special Protection System status,” while the NOPR references only Special Protection Schemes.
Individual
Rich Salgo
NV Energy
Yes
No
The changes made to R2 and R5 are responsive to our prior concerns. However, the language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the “authority to approve” doesn’t literally mean the same thing as “work shall not be performed without RC approval.” The latter appears to be what the SDT intends, but the language does not appear to support it.
Yes
No
We understand the SDT’s intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don’t believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. We suggest the following language: Each Planning

Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
No
The SDT has made a number of improvements to this particular standard in this latest posting. We are troubled by the following items: Definition of Real-Time Assessment contains two provisions that will make compliance with the Requirements unattainable. First, the applicable inputs to the assessment include among other things, “known Protection System status or degradation.” Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation. Secondly, the real time assessment is to consider “identified phase angle and equipment limitations.” We are unclear as to whether this is intended to mean the identification of post-contingent standing phase angles (which current RTCA tools are ineffective at modelling and assessing) or alternatively, the identification of the angular limitations of power system equipment, such as sync check permission settings for circuit breakers. Such analyses are more readily conducted using on line power flow tools, and do not lend themselves to the real-time environment. We understand that the insertion of the modifier “applicable” may provide some relief in these considerations, but we fear that compliance enforcement will not allow discretion as to what inputs are applicable and which are not. We appreciate the significant improvement with regard to the language in Requirement R10. With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would suggest the following: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform with this R13 language.
No
We are troubled by the removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3. This unnecessarily opens the requirement scope to an un-provable state. Suggest restoring the modifier “NERC registered” in front of “entities.”
Yes
Individual
Terry Harbour
MidAmerican Energy Company
Yes

No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. The language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the "authority to approve" doesn't literally mean the same thing as "work shall not be performed without RC approval." The latter appears to be what the SDT intends, but the language does not appear to support it.
No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of

equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions.
No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions.
Yes
No
MidAmerican understands the SDT's intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don't believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. MidAmerican suggests the following language: Each Planning Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time

assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. With regard to R13, MidAmerican believes the SDT has improved the language by revisions such that the TOP shall "ensure that a Real-time Assessment is performed at least once every 30 minutes;" however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, MidAmerican suggest the following: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP."
No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time

Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. Removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3 opens the requirement scope to an un-provable state and potential non-compliance. MidAmerican suggests the modifier “NERC registered” be restored in front of “entities.”
No
MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency). Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU’s etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions.
No
Yes
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes

Yes
Yes
Yes
No
Regarding R4, Transmission Planning Assessments for the Near Term Planning Horizon do not consider outages that are less than one year in duration. If the transmission system is incapable of serving expected peak load during the Near Term Planning Horizon, current TPL standards and the future TPL-001-4 dictate Corrective Action Plans be undertaken and put in place. As currently written, R4 appears to be duplicative of TPL-001-4. BPA suggests R4 be rewritten to direct TOP and BA coordinate outages conflicts within the Operations Planning Horizon. BPA believes altering R4 in this fashion covers the reliability gap identified by the SW Outage Report, the IERP and FERC with respect to planning of outages. Additionally, this change will logically align R4 with R1.1.2, and R2, directing coordination between RC and TOP/BA.
No
BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, "… operations that result in, or could result in, an Emergency." It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard conflates events that are actually happening with events that may happen at some point. BPA suggests the drafting team clearly separate these two concepts. Specifically, R8 requires entities to identify "… operations that result in, or could result in, an Emergency," without any qualification for likelihood. BPA does not feel it is appropriate to treat an actual Emergency the same way it treats a possible future Emergency that could, but likely will not happen.
No
BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement.
Yes
No
Yes

No
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
1. The term Operating Instruction is defined as a command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.) Because the definition of Operating Instruction is focused on real-time activities necessary to preserve the real-time status and condition of the BES and indicates that such activities may only be issued by operating personnel responsible for the Real-time operation of the BES, ERCOT suggests that the use of the term Operating Instruction within the multiple time horizons referenced throughout IRO-001-4 (especially the operations planning and same-day operations time horizons) undermines the objectives of issuing Operating Instructions in Real-Time, are likely to cause confusion regarding the Operating Instruction an entity should implement, and would result in significant resource and operational concerns. First, because the term Operating Instruction as developed and utilized in COM-002-4 is intended to provide operating personnel responsible for the real-time status and condition of the BES with additional tools and authority to prevent miscommunications and ensure the reliability of the BES, its definition has been tailored to real-time scenarios and responsibilities. Indeed, the very definition is focused on responding to emerging conditions within the BES to ensure reliability, connoting urgency and ensuring that the issuer’s authority and direction is unchallenged and timely implemented. This sense of urgency and authority that provided additional strength to Reliability Coordinators in fulfilling obligations under COM-002-4 is weakened significantly when the term Operating Instruction is applied to activities expected to be performed days in advance of target operating day. Specifically, because the activities identified as mitigations to forecasted system conditions are based on forecasts and best available information in advance of the actual operating day, such conditions may never manifest themselves and the “command” issued may never need to be implemented. Accordingly, the use of the term Operating Instruction within Same-Day and Operations Planning Horizons is likely to cause confusion as the directed activities may never need to be taken, but would essentially be defined through the use of the term Operating Instructions, as “urgent” actions. Additionally, entities being issued advance “Operating Instructions” may become confused regarding what activities they should perform if Operating Instructions devised as a result of a Next-Day Study differed from the Operating Instructions received in Real-Time. Generally, actions in advance of the target operating day are coordinated amongst impacted entities with the objective of ensuring that operating parameters are respected should adverse conditions manifest during the target operating

day. These activities are generally plans that are developed prior to the target operating day in response to forecasted conditions. As discussed earlier, the term Operating Instruction was devised to provide Reliability Coordinators and other responsible entities with the tools and authority necessary to proactively ensure the reliability of the BES in real-time. Plans developed in response to forecasted conditions that may or may not manifest themselves are not and should not equated with actions that should be taken immediately to preserve reliability. Finally, ERCOT notes potential resource and operational concerns with requiring Reliability Coordinators to utilize their operating personnel responsible for Real-time activities to issue Operating Instructions that would result from Operational Planning Analyses conducted well in advance of real-time. In particular, because the definition of Operating Instruction requires that such an instruction be issued by operating personnel responsible for the real-time operation of the BES (which is generally interpreted synonymously with “system operator”), ERCOT respectfully submits its significant concerns regarding diverting its real-time personnel and resources to tasks generally performed by personnel focused on the day-ahead or operations planning time horizons. More specifically, Operational Planning Analyses are generally performed by personnel that are not considered operating personnel, but are, rather Operations Support Personnel or other technical personnel. The review, analysis, and final decisions regarding necessary actions, while coordinated with operating personnel, are generally completed and communicated by those same personnel. To issue Operating Instructions for analyses performed in the forward planning horizons would require diversion of operating personnel from their primary tasks in the real-time environment to tasks generally performed by personnel focused on operations planning. ERCOT respectfully submits that such would not only cause resource concerns by diverting real-time personnel from ensuring the reliability of the BES, but would also cause operational concerns as entities receiving such Operating Instructions from personnel that are essentially System Operators may cause confusion regarding when such Operating Instructions should be implemented. To resolve the foregoing concerns, ERCOT respectfully suggests that the Standards Drafting Team (SDT) insert the term “directive” or other verbiage where the use of Operating Instruction is intended to address multiple time horizons until the definition of operating instruction is modified or – should such modification not be possible –permanently (e.g., IRO-001-4, R1, R2, and R3) and coordinated with COM-002-4. As it stands today, applying the term to more than the Real Time horizon will likewise expand the scope of communications that must be addressed in COM-002-4 R1-R3. R1. Each Reliability Coordinator shall act, or direct others to act, by issuing directives or Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] 2. To ensure consistency amongst requirements within the IRO-001-4 standard, it is recommended that Requirement R3 be revised to more closely reflect its triggering or immediately preceding requirement, Requirement R2. The proposed Requirement R3 would read: R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition that the Operating Instruction issued by its Reliability Coordinator pursuant to Requirement 1 cannot be physically implemented or

would violate safety, equipment, regulatory, or statutory requirements. Additionally, it is recommended that the associated VSL also be modified accordingly.
No
1. ERCOT respectfully submits that Requirement R1 is duplicative to COM-001, R1 and recommends that it remain deleted. 2. ERCOT respectfully suggests that Requirement R2 requires clarification regarding the entities with which a Reliability Coordinator shall have data exchange capabilities and what shall constitute such data exchange capabilities as some information sharing does not lend itself to data links. The following revisions are proposed: R2. Each Reliability Coordinator shall exchange data with Balancing Authorities, Transmission Operators, and other entities as identified in the data specification developed and maintained in accordance with IRO-010 and necessary to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. [Violation Risk Factor: High] 3. ERCOT respectfully suggests that Requirement R3 may be confusing and redundant as written and proposes a streamlined, less ambiguous version for the SDT's consideration. The following revisions are proposed: R3. Each Reliability Coordinator shall monitor the Facilities, status of Special Protection Systems, and sub-100 kV facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas that are necessary to identify System Operating Limit exceedances and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
No
1. ERCOT respectfully submits that Requirement R3 is ambiguous as written. More specifically, the use of terms such as "coordinated" and "considered" are undefined and unnecessarily complicate Reliability Coordinator's responsibilities and documentation. In R2-R3, the current definition of Operating Plan states "a document". While this context is appropriate for processes/procedures determined well in advance of real time (e.g. EOP 005, EOP 008). The timeframe described is really next day and while most "Operating Plans" are documented, all plans to operate reliably may not be documented or in "a document". The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having "a document" rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single "document" and have several required elements. This can be overly prescriptive and burdensome. 2. ERCOT respectfully submits that Requirement R4 is ambiguous as written. More specifically, it is unclear as to whether the Reliability Coordinator is responsible for notification of those entities impacted in its Operating Plan or all Operating Plans referenced in Requirement R3. 3. ERCOT suggests that the SDT review the language of Requirement R5 and its VSL for consistency. In particular, Requirement R5 was modified to require that the Reliability Coordinator ensure that a Real-Time Assessment is performed every 30 minutes. However, the VSL still assesses the condition that the Reliability Coordinator did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. These should

be reviewed and revised to ensure consistency between the requirement and its VSL. 4. ERCOT respectfully notes that Requirement R5 and the associated VSLs do not acknowledge the necessary tool outages that occur as part of planned system maintenance to ensure that Reliability Coordinator tools continue to run with high availability and accuracy. With the continuing obligations of Registered Entities to ensure the cybersecurity of their tools and the clear acknowledgment of the need for planned outages of Reliability Coordinator tools in IRO-002-4, R3, the current Requirement R5 and the associated VSLs create conflict and inconsistency amongst the overall set of Reliability Standards. If Registered Entities (and Reliability Coordinators in particular) are required to maintain their analysis tools, which maintenance may require outages of such tools, Requirement R5 should not provide that Reliability Coordinators will be penalized for the very activities they are required to conduct under its obligations set forth within the overall set of enforceable Reliability Standards. More clearly stated, it should not be a violation if an entity has a planned tool outage that causes a reasonable time deviation from the normal 30 minute timeframe. The following revisions are proposed are proposed to address this inconsistency: R5. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes except where performance is delayed as a result of a planned or unplanned tool outage and potential effects of the delay are mitigated where possible. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations] It is further recommended that the associated VSLs also be modified accordingly. 5. ERCOT has identified a potential typographical error in R6 and all of its VSLs. Specifically, the reference to “as identified in identified in Requirement R6” should likely be reviewed and revised to “as identified in Requirement R5”. 6. ERCOT respectfully reiterates its previous comment on the inconsistent language used between Requirements R5 and R6 and the LOWER VSL for Requirement R8. In particular, the word “Emergency” is used in the VSL for Requirement R8 but the condition is not specified elsewhere in the standard or the appropriate referenced requirements. Please revise the lower VSL for Requirement R8 to ensure consistency. The following language is proposed: “when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated”. 7. The reference in Requirements R6 and R8 to “as indicated in its Operating Plan” is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly and can cause a “plan” to vary and the impacted entities to vary. The phrase “as indicated in its Operating Plan” should be deleted. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of “Operating Plan” and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.
No
Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc.

ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
No
1. ERCOT notes that the consolidated set of IRO and TOP Reliability Standards utilize the terms “Wide Area” and “Reliability Coordinator Area”. If these phrases are expected or interpreted to be synonymous, ERCOT suggests use one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion. 2. To ensure consistency, ERCOT recommends that, in Requirement R1.6, “provisions for” is removed and the sub-requirement begins with “Periodic”. 3. ERCOT respectfully recommends deletion of Requirement R3 as it is duplicative of IRO-008, Requirements R4 and R6. If the distinguishing factor and reason for inclusion is the acknowledgment of Emergency conditions, ERCOT recommends that such language is added to IRO-008. 4. ERCOT respectfully recommends deletion of Requirement R4 as it has been rendered moot by revisions to Requirement R6 and R7. Specifically, since Requirement R6 requires impacted Reliability Coordinators to implement any action plan developed by the Reliability Coordinator with the emergency and Requirement R7 requires assistance so long as the Reliability Coordinator with the emergency has implemented its emergency procedures, the dictation of operating state by other Reliability Coordinators is unnecessary. 5. ERCOT respectfully recommends deletion of Requirement R5 as it is duplicative of IRO-001-4, Requirement R1. Specifically, since Reliability Coordinators always have primary responsibility and ultimate authority to act when they observe conditions in their area that threaten reliability, disagreement with the Reliability Coordinator’s assessment of the conditions by another entity is of no consequence. However, if the objective is to ensure that Reliability Coordinators assist each other in Emergencies, Requirements R5 and R7 could be eliminated and Requirement R6 could be modified as follows: R6. Each impacted Reliability Coordinator shall implement any actions and/or provide any assistance requested by the Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area unless such actions would violate safety, equipment, regulatory, or statutory requirements. 6. ERCOT respectfully notes that it is unable to discern the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. ERCOT urges the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays. 7. ERCOT respectfully recommends that, for consistency, the VSLs for Requirement R2 be modified to remove references to criteria and state that Reliability Coordinator failed to maintain Operating Plans, Processes, or Procedures pursuant to one part of Parts 2.1 – 2.3, two parts of Parts 2.1 – 2.3, and so on. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of “Operating Plan” and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered

Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.
No
1. As an overarching comment, the proposed standard references both transmission and generation outages, but then appears to focus in on transmission outages. As a result, entities responsible for generation outages do not appear to be adequately addressed relative to potential obligations to comply with Reliability Coordinator processes that are developed. This oversight could have significant consequences and the standard should be reviewed to ensure that no gaps exist. At a minimum, those entities responsible for generator outages should be included under the Applicability Section as well as other applicable Requirements (e.g., Requirement R2). More specifically, during the last posting, ERCOT commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While ERCOT agrees that such details can be elaborated in the process document, Part 1.1.2 and other requirements should be expanded to include all appropriate entities to facilitate RC development of a workable and appropriate outage coordination process involving the correct entities. 2. ERCOT is unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2 as discussed above. ERCOT respectfully notes that Requirement R1 requires some revisions to ensure clarity and ensure that the obligations imposed are clear and unambiguous. Specifically, the requirement indicates that Reliability Coordinators shall develop, implement, and maintain and outage coordination process. However, it does not define what maintenance shall be performed. R1. Each Reliability Coordinator shall develop and implement an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] ERCOT believes "develop" in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 "document and" with "maintain", which is sufficient. Document is purely administrative. M1 infers a requirement by including "dated". By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. Additionally, it is noted that use of the term "define" may not adequately connote the level of detail expected regarding the documentation of the outage evaluation and coordination process referenced in sub-requirements R1.3 and R1.4. Accordingly, the following revisions are suggested: 3. ERCOT respectfully notes that Requirement R2 requires some revisions to ensure clarity and ensure that the obligations imposed upon participants in each Reliability Coordinator's outage coordination process are clear and unambiguous. Accordingly, it is recommended that Requirement R2 be modified as follows: R2. Each Transmission Operator and Balancing Authority shall perform the roles,

responsibilities, and activities assigned to its function in its Reliability Coordinator outage coordination process. [Violation Risk Factor: LowMedium] [Time Horizon: Operations Planning] 4. ERCOT respectfully notes that TPL-001-4 already requires distribution of Planning Assessments to various entities. To ensure that all obligations related to Planning Assessments are clearly communicated and consolidated such that they are easily identified and fulfilled, it is recommended that Requirement R3 be deleted from IRO-017 and Requirement R8 within TPL-001-4 be reviewed for the necessary revisions.
No
Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: “Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]”. This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states “a document”. Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term “Operating Instruction” outside of real time. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
No
The current definition of Operating Plan states “a document”. Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4. For R4, the SDT should consider consistency of use of “Demand patterns” and “Load Forecast”.
No
Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Yes

During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT's response indicates that "it has revised the whitepaper to include "as necessary and appropriate". However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that "All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan." If there is a basecase exceedance, the entity should take all actions up to and including shedding load within the timeframe to protect the equipment. If the entity is somewhere between the 4 hr. and 15 min. rating they have up to 15 min to get below the continuous (normal) rating for a basecase (pre contingency) exceedance.
Yes
Except as noted.
Yes
The proposed definitions of Real-Time Assessment and Operational Planning Analysis require use of applicable inputs. ERCOT respectfully submits that many of these inputs can only be utilized once communicated by other entities. Accordingly, the following revision is proposed: Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable, known inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted third-party services.) Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable, known inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted third-party services.) During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are

based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any “proven reliable power system limits” as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a “white paper” status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary action to “restore operations to respect proven reliable power system limits within 30 minutes” when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.

Additional Comments

City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power

John Merrell

TOP-001-3 Requirement R9 states that the RC will be notified of all outages of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels without regard to being a planned or a unplanned outage. This will most likely result in overburdening of operating personnel and the RC being inundated with phone calls. A majority of calls will likely be notifications of unplanned outages that are short in duration and of no real impact to the interconnection. Tacoma recommends the word “planned” be added to R9 as it is in M9 such that all planned outages are communicated.

City of Austin dba Austin Energy
Thomas Standifur

1. Do you agree with the changes made to respond to industry comments to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:
   No: X

   Comments: (1) City of Austin dba Austin Energy (AE) continues to disagree with the change to R1, which removes the “clear decision-making authority” language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. AE believes the remaining requirements in the TOP/IRO families instruct the RC or TOP to “act, or direct others … to act” while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. (2) AE understands the SDT’s intent in including the Operations Planning time horizon with respect to Operating Instructions is to cover the concept of “next day directives” previously in IRO-004. AE also understands there is no Next-Day Planning time horizon available. AE requests the SDT make its intent clear by adding additional language to the requirement, the rationale box or a Guidelines and Technical Basis section so it is not lost that the SDT expects Operating Instructions to be limited to next day, same day or real-time situations. This aligns with the concept of Operating Instructions coming out of Operations Planning Analyses, Real-Time Assessments and Real-Time operations. It would remove confusion that Operating Instructions could occur anytime within the Operations Planning time horizon.

4. Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X
   No:

6. The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new

standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes:
No: X

Comments: City of Austin dba Austin Energy (AE) AE believes R3 and R4 are redundant with requirements in TPL-001-4. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. AE notes the SDT's response in comments, "The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document." AE suggests these changes should all be considered under the TPL-001-5 SAR and not in a separate IRO-017-1 standard.

7. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes:
No: X

Comments: City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments: (1) AE continues to disagree with the change to R1, which removes the "responsibility and clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to "act, or direct others … to act" while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. (2) AE understands the SDT's intent in including the Operations Planning time horizon with respect to Operating Instructions is to cover the concept of "next day directives" previously in IRO-004-2. However, IRO-004-2, as written is limited to RC directives. AE suggests the SDT remove the Operations Planning Horizon from R1. (3) R9 is too broad a scope to be useful. The phrase "…outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels…" is all encompassing. If each BA or TOP were to contact the RC every time there was the slightest glitch with telemetering or every time an ICCP link or microwave channel was cycled for maintenance or some type of momentary signal fade, the RC's phone would be ringing continually. The intent of this requirement is to be sure all entities are aware of a

loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 is sufficient to meet the intent. See suggested wording below:
Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. (4) R19 and R20 are redundant with existing COM standards. They will remain redundant when future COM standards come into effect. AE requests the SDT remove these added requirements from TOP-001-3.

8. Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X
   No:

9. Do you agree with the changes made to respond to industry comments to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes: X
   No:

11. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements and to respond to industry comments. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

    Yes:
    No: X

    Comments: City of Austin dba Austin Energy (AE) provides the following comments regarding VSLs: (1) The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. That is, the moderate level should be lower, the high should be moderate and the first half of severe should be high.

12. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

    Yes:
    No: X

SCE&G
RoLynda Shumpert

1. Do you agree with the changes made to respond to industry comments to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes.

2. Do you agree with the changes made to respond to industry comments to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: The OC Review Group suggests adding the word 'its' between 'with' and 'Balancing Authorities' to provide clarity.

   Suggested Wording: "R2: Each Reliability Coordinator shall have data exchange capabilities with **its** Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments."

3. Do you agree with the changes made to respond to industry comments to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R5, the OC Review Group suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service.

   In R8, the OC Review Group suggests removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs.

   Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been ~~**prevented or**~~ mitigated."

4. Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes.
Comments: Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?

5. Do you agree with the changes made to respond to industry comments to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R1.1, the OC Review Group suggests adding "as identified in R1" at the end of the sentence to identify the criteria and process being addressed.

   Suggested Wording: "R1.1: Criteria and processes for notifications **as identified in R1**."

   The OC Review Group suggests adding "may" before "impact adjacent Reliability Coordinator Areas" in M1 to match R1.

   Suggested Wording: "M1: Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that **may** impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

6. The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R2, the OC Review Group suggests changing the word "function" to "roles and responsibilities" to match R1.

   Suggested Wording: "R2: Each Transmission Operator and Balancing Authority shall perform the ~~functions~~ **roles and responsibilities** specified in its Reliability Coordinator outage coordination process."

   In R4, the OC Review Group suggests adding "on the BES" before "with planned outages" to clearly define the BES as the subject portion of the system.

   Suggested Wording: "R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts

on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon."

7. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.

   Comments: With regard to R13, we understand and support the need to do real-time assessments at least once every 30 minutes to avoid being in an unstudied state. However, if significant SCADA losses occur or an ICCP link is lost to a neighboring BA/TOP, the State Estimator solution can be affected to such a degree that a real-time assessment, <u>with real-time data</u>, may not be possible within 30 minutes. While this does not happen often, it does occur on occasion, but the requirement allows for NO exceptions to the 30 minute requirement. (As an example. the MOD-001 standard allows for a certain number of hours that ATC may not be recalculated without being in non-compliance).

8. Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.

   Comments: In R1, the OC Review Group suggests adding the word "identified" before "SOLs" to clarify transmission operators are operating to the identified SOLs.

   Suggested Wording: "R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its **identified** System Operating Limits (SOLs)."

9. Do you agree with the changes made to respond to industry comments to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes.

   Comments: Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?

10. Do you have any comments on the changes made to respond to industry comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.

    Yes.

11. The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements and to respond to industry comments. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.

    No.
    Comments: See comments above for specific suggestions for changes to VSLs.

12. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

    No.

Georgia System Operations Corporation

2. Do you agree with the changes made to respond to industry comments to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.

   Comments: GSOC suggests adding the word 'its' between 'with' and 'Balancing Authorities' to provide clarity.

   Suggested Wording: "R2: Each Reliability Coordinator shall have data exchange capabilities with **its** Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments."

3. Do you agree with the changes made to respond to industry comments to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R5, the GSOC suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service.

   In R8, the GSOC suggests removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs.

   Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit

(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been ~~**prevented or**~~ mitigated."

4. Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Comments: Do you agree with the changes made to respond to industry comments to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R1.1, the GSOC suggests adding "as identified in R1" at the end of the sentence to identify the criteria and process being addressed.

   Suggested Wording: "R1.1: Criteria and processes for notifications **as identified in R1**."

   The GSOC suggests adding "may" before "impact adjacent Reliability Coordinator Areas" in M1 to match R1.

   Suggested Wording: "M1: Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that **may** impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

5. The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R2, the GSOC suggests changing the word "function" to "roles and responsibilities" to match R1.

   Suggested Wording: "R2: Each Transmission Operator and Balancing Authority shall perform the ~~functions~~ **roles and responsibilities** specified in its Reliability Coordinator outage coordination process."

   In R4, the GSOC suggests adding "on the BES" before "with planned outages" to clearly define the BES as the subject portion of the system.

   Suggested Wording: "R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts **on the BES** with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon."

6. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments:

   The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability.

   R3 and R4 state that only the registered entities identified **must comply** with OI; they do not state that registered entities identified are the only entities that **can receive** OI. Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply.

   Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2.

   Suggested Wording: R1 and R2: "Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area."

   In R10, replace "necessary" with "applicable" to maintain consistency with the definitions of Real-Time Assessment and Operational Planning Analysis.

   Suggested Wording: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as ~~**necessary**~~ **applicable** by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area

   In R13, the GSOC suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service.

   In the R13 VSL, the GSOC suggests the time graduations for each level of VSL be retained (30-35 minutes, 30-40 minutes, 40-45 minutes, >45 minutes).

In R18, the GSOC suggests removing the word "always" before "operate" and provide graduated VSL to allow for when limits were determined to be incorrect due to mistake in entry of data.

Suggested Wording: "R18: Each Transmission Operator and Balancing Authority shall **~~always~~** operate to the most limiting parameter in instances where there is a difference in SOLs."

Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?

7. Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   No.
   Comments: In R1, the GSOC suggests adding the word "identified" before "SOLs" to clarify transmission operators are operating to the identified SOLs.

   Suggested Wording: "R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its **identified** System Operating Limits (SOLs)."

12. Are there any other concerns with these standards that haven't been covered in previous questions and comments?

    No.

Consideration of Comments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

The Project 2014-03 Drafting Team (SDT) thanks all commenters who submitted comments on the TOP/IRO Reliability Standards. These standards were posted for a 45-day public comment period from August 6, 2014 through September 19, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 59 sets of comments, including comments from approximately 166 different people from approximately 95 companies representing 8 of the 10 industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standards' project page.

Summary Consideration:

The SDT appreciates the careful review stakeholders provided of this large volume of standards and thanks stakeholders for their support in completing this project. The SDT has made a number of changes to each of the standards in response to stakeholder comments.

TOP-001-3 was the only standard requiring substantive changes, as well as a number of clarifying changes, in response to stakeholder comments. The SDT made the following changes to proposed TOP-001-3:

- Deleted *Operations Planning* time horizon from all requirements dealing with Operating Instructions
- Requirements R1 and R2 – changed 'ensure' to address'; clarified language on actions and issuance of Operating Instructions
- Requirement R7 – capitalized 'E' in Emergency
- Requirement R8 – deleted 'other'
- Requirement R9 – added 'sustained' to outages; deleted 'NERC registered'; merged 'telemetering and control'
- Requirement R10 – completely restructured for clarity on what needs to be monitored
- Requirement R11 – replaced 'ensure'
- Requirement R15 – grammatical changes
- Requirement R16 – Changed 'Real-time Assessment' to 'analysis'
- Requirement R18 – deleted 'Balancing Authority'; deleted 'always'
- Requirements R19 and R20 – corrected typographical errors

In response to stakeholder comments, the SDT has made only clarifying and non-substantive changes to the other eight standards, as follows:

- IRO-001-4
  - Deleted *Operations Planning* time horizon from all requirements dealing with Operating Instructions
  - Requirement R1 - changed 'ensure' to 'address;' clarified language on actions and issuance of Operating Instructions
  - Measure M2 – deleted 'Transmission Service Provider' to conform to Requirement R2
  - Data retention – deleted 'Transmission Service Provider' to conform to Applicability
- IRO-002-4
  - Requirement R1 – made grammatical change
  - Requirement R3 – replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- IRO-008-2
  - Requirement R3 – made grammatical changes
  - Requirement R5 – deleted 'Reliability Coordinator' from 'Wide Area'
  - Requirement R6 – corrected typographical error
- IRO-010-2
  - Requirement R1, Part 1.1 – replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- IRO-014-3
  - Measure M1 – added 'may' impact
  - Requirement R5 – corrected tense
  - Requirement R6 – corrected tense
  - Data retention – corrected requirement numbering
- IRO-017-1
  - Requirement R1, Part 1.3 – replaced 'generator' with 'generation'
  - Requirement R2 – made 'entity' plural
  - Requirement R3 – changed time horizon from 'Operations Planning' to 'Long-term Planning'
- TOP-002-4
  - Measure M2 – added 'exceedances' term
  - Requirements R3 and R5 – deleted 'impacted'
- TOP-003-3
  - Requirement R1, Part 1.1 - replaced 'sub-100 kV' with 'non-BES' to clarify the drafting team's intent
- SOL Exceedance White Paper
  - Made several clarifying changes
- Violation Severity Levels
  - IRO-008-2, Requirement R3 – deleted NERC registered;' changed 'less than' to 'greater than;' made grammatical change
  - IRO-008-2, Requirement R4 – deleted first part of Severe VSL

- o IRO-014-3, Requirement R2 – changed 'address' from 'meet;' changed from 'criteria' to 'parts'
- o IRO-014-3, Requirement R7 – corrected tense of verbs
- o IRO-017-1, Requirement R2 – changed entity to plural in Severe VSL
- o TOP-001-3, Requirements R1 and R2 – restructured language to match requirement
- o TOP-001-3, Requirement R7 – corrected grammatical errors
- o TOP-001-3, Requirement R8 – deleted 'whichever is less;' deleted 'other'
- o TOP-001-3, Requirement R9 – deleted 'whichever is less'
- o TOP-001-3, Requirement R10 – changed from binary approach to incremental approach
- o TOP-001-3, Requirement R13 – corrected numeric error in Severe VSL
- o TOP-002-4, Requirement R3 – corrected 'NERC entities' language
- o TOP-002-4, Requirement R5 – deleted 'impacted;' changed 'less than' to 'greater than'
- o TOP-003-3, Requirement R5 – added Lower VSL; deleted first part of severe VSL

The SDT is recommending that proposed TOP-001-3 be posted for an additional comment period and ballot, and that the other standards, definitions, and Implementation Plan be posted for final ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Ben Engelby	ACES Standards Collaborators	X		X	X	X	X				

Additional Member		Additional Organization	Region	Segment Selection
1.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 5
2.	Ginger Mercier	Prairie Power, Inc.	SERC	3
3.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
3.	Group	Patricia Robertson	BC Hydro	X	X	X		X					

Additional Member	Additional Organization	Region	Segment Selection	
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat G Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5

				1	2	3	4	5	6	7	8	9	10
4.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Steve Hitchens	Technical Operations	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Berhanu Tesema	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
5.	Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Doug Hils			1
2.	Lee Schuster			3
3.	Dal Goodwine			5
4.	Greg Cecil			6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Randy Hahn	Ocala Utlity Service	FRCC	3
6.	Don Cuevas	Beaches Energy Services	FRCC	1
7.	Stan Rzad	Keys Energy Services	FRCC	4
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
10.	Steve Lancaster	Beaches Energy Services	FRCC	3
11.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
12.	Mike Blough	Kissimmee Utility Authority	FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Greg Campoli	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ben Li	IESO	NPCC	2
2.	Charles Yeung	SPP	SPP	2
3.	Matt Goldberg	ISO-NE	NPCC	2
4.	Terry Bilke	MISO	RFC	2
5.	Ali Miremadi	CAISO	WECC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Randi Heise	NERC Compliance Policy	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Garton	Dominion	NPCC	5
2.	Connie Lowe	Dominion	RFC	6
3.	Louis Slade	Dominion	SERC	2, 5
4.	Chip Humphrey	Dominion	RFC	5
5.	Latrry Nash	Dominion	SERC	1, 3
6.	Sandra Hopkins	Dominion	SERC	6
7.	Jeffrey N. Bailey	Dominion	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Guy Zito	Northeast Power Coordinating Council	X	X	X		X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

				1	2	3	4	5	6	7	8	9	10
12.	Group	Robert Rhodes	SPP Standards Review Group	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Bensky	ITC Holdings	SPP	1
2.	Kaleb Brimhall	Colorado Springs Utilities	WECC	1, 5, 6
3.	Michelle Corley	Cleco Power LLC	SPP	1, 3, 5, 6
4.	Dave Dieterich	Omaha Public Power District	MRO	1, 3, 5
5.	Neal Faltys	Omaha Public Power District	MRO	1, 3, 5
6.	Todd Gosnell	Omaha Public Power District	MRO	1, 3, 5
7.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5, 6
8.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
9.	Vinit Gupta	ITC Holdings	SPP	1

10. Jonathan Hayes	Southwest Power Pool	SPP	2
11. Robert Hirchak	Cleco Power LLC	SPP	1, 3, 5, 6
12. Brett Holland	Kansas City Power & Light	SPP	1, 3, 5, 6
13. Mike Kidwell	Empire District Electric	SPP	1, 3, 5
14. Thomas Mayhan	Omaha Public Power District	MRO	1, 3, 5
15. Gregory McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
16. Shannon Mickens	Southwest Power Pool	SPP	2
17. Mike Moltane	ITC Holdings	SPP	1
18. James Nail	City of Independence, MO	SPP	3, 5
19. Si Nguyen	Omaha Public Power District	MRO	1, 3, 5
20. Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
21. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
22. Jon Shipman	Omaha Public Power District	MRO	1, 3, 5
23. Josh Verzal	Omaha Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	Individual	David Jendras	Ameren	X		X		X	X				
14.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
15.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
16.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
17.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X							
18.	Individual	Scott Langston	City of Tallahassee	X									
19.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
20.	Individual	Jack Stamper	Clark Public Utilities	X									
21.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
22.	Individual	Eric Sutlief	Consumers Energy Company			X	X	X					
23.	Individual	Glenn Pressler	CPS Energy	X		X		X					
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Russell Schneider	Flathead Electric Cooperative, Inc.			X	X						
26.	Individual	Scott Knewasser	FRCC Compliance										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	John A. Libertz	FRCC Operating Committee (Member Services)	X									
28.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
29.	Individual	Daniel Mason	HHWP					X					
30.	Individual	Ayesha Sabouba	Hydro One	X		X							
31.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
32.	Individual	Dave Willis	Idaho Power Company	X									
33.	Individual	Leonard Kula	Independent Electricity System Operator		X								
34.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
35.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration , LP					X					
36.	Individual	Michael Moltane	ITC	X									
37.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
38.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
39.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
40.	Individual	Terry Harbour	MidAmerican Energy Company	X									
41.	Individual	Gregory Campoli	New York Independent System Operator (NYISO)		X								
42.	Individual	Bill Temple	Northeast Utilities	X									
43.	Individual	Robert Fox on behalf of David Austin	Northern Indiana Public Service Company (NIPSCO)	X		X		X	X				
44.	Individual	Rich Salgo	NV Energy	X		X		X					
45.	Individual	Joshua Smith	Oncor Electric Delivery LLC	X									
46.	Individual	Sandra Shaffer	PacifiCorp						X				
47.	Individual	Jared Shakespeare	Peak Reliability	X									
48.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
49.	Individual	Catherine Wesley	PJM Interconnection		X								
50.	Individual	Denise M. Lietz	Puget Sound Energy	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	Anthony Jablonski	ReliabilityFirst										X
52.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
53.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
54.	Individual	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
55.	Individual	Joel Wise	Tennessee Valley Authority	X		X						X	
56.	Individual	Karin Schweitzer	Texas Reliability Entity										X
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Steve Johnson	Western Area Power Administration	X		X							
59.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				

1. **Do you agree with the changes made to respond to industry comments to proposed IRO-001-4? If not, please provide technical rationale for your disagreement along with suggested language changes**.

Summary Consideration: The SDT deleted 'Operations Planning' from all time horizons concerning Operating Instructions as Operating Instructions are issued in Real-time environments.

R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

1.3. Data Retention

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Organization	Yes or No	Question 1 Comments
ACES Standards Collaborators	No	(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) Requirement R1 should be revised by removing the words "direct others to act" and stating that the RC shall issue Operating Instructions. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and

Organization	Yes or No	Question 1 Comments
		may not fully capture what the drafting team is trying to achieve. For example, by stating that the RC shall act or direct others to act by issuing an Operating Instruction, the RC is limited only to this option. We recommend alternative language for this requirement, "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." (3) Requirement R1's language of requiring the RC to "ensure reliability" could be used as a zero defect standard if there is an event. "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." (4) The rationale for requirements R2 and R3 contradict with the revisions to the requirements. The rationale states that the TSP was added to allow retirement of IRO-004-2, but the draft removes the TSP from the requirements. Is the intent to keep IRO-004-2 intact? (5) Requirement R3 should be merged with R2. We suggest the following language for consideration, "Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Reliability Coordinator, or shall inform its Reliability Coordinator of its inability to perform because it cannot be physically implemented or such actions would violate safety, equipment, regulatory, or statutory requirements." This revision captures the intent of both requirements, is consistent with TOP-001, and reduces the amount of requirements needed. It also reduces unnecessary compliance exposure since only one violation could occur rather than potentially two requirements being violated.
Response: 1. Thank you for your support. 2. The SDT agrees and has revised the wording of the requirement. See summary for wording. 3. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. 4. The SDT agrees and has corrected the language in the rationale box. 5. The SDT believes both requirements are needed independently and combining them using the proposed language creates essentially two requirements in one which should be avoided. No change made.		

Organization	Yes or No	Question 1 Comments
Georgia Transmission Corporation	No	(1) We agree with the removal of the PSE and LSE from the applicability section of IRO-001-4. (2) The current proposal for R2 as written could overly expose the DP to excess and double jeopardy compliance obligations for routine switching operations DPs perform on a daily basis which does not affect the reliability of the BES. Daily switching which require Operating Instructions could include scheduled outages for maintenance items and new construction. The functional model clearly states that RCs "...Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators". Based on this, one could assume the Operating Instruction issued by an RC to a DP would be limited to a load shedding scenario and not daily switching routines mentioned above. However, this arrangement becomes less clear when the issuer of the Operating Instruction has multiple registrations with NERC as the RC, BA, and TOP; and when the recipient of the operating instruction is registered with NERC as a DP, TO, and TSP. Under such exchange, a single Operating Instruction issued from such an entity is technically an Operating Instruction from the RC, BA, and TOP; the recipient of this single Operating Instruction also applies to each of their registration type being a DP, TO, and TSP. To the auditor, this single Operating Instruction could be the same piece of evidence for multiple requirements across multiple Standards such as IRO-001 and TOP-001. GTC believes the RC to DP interaction (with the RCs wide area view) is limited to Emergency scenarios which warrant a separate requirement for clarification of such exchange. A separate requirement for the DP is also justified and helps the ambiguity surrounding Real Time vs Ahead of Time activities within scope of the RC. The RC could issue Operating Instructions to the TOP, BA, GOP and IA for both Real Time and Ahead of Time, but GTC believes the DP is limited to Real Time horizon associated with "load shed" only in order for the RC to ensure the reliability of its Reliability Coordinator Area. A standalone requirement would correct the ambiguity expressed above and would more accurately capture the scenario of when the RC would be issuing Operating Instructions to the DP rather than BA, TOP, GOP, etc. Again, GTC's goal is for

Organization	Yes or No	Question 1 Comments
		this requirement not to overlap on the daily switching routines performed by the DP which require Operating Instructions such as scheduled outages for maintenance items and new construction when the issuing entity has both registrations of RC and TOP.GTC proposes the following standalone requirement for the DP: "Each Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions associated with load shed unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements." Alternately, GTC would accept "Each Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions during an Emergency unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements."
Response: 1. Thank you for your support. 2. The SDT agrees that Operating Instructions from the Reliability Coordinator to the Distribution Provider would most likely be limited to a Load shedding scenario; however the SDT does not believe a separate requirement for Reliability Coordinator to Distribution Provider communication is needed because the current wording in Requirements R2 and R3 covers this communication. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. The term Operating Instruction is defined as a command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.) Because the definition of Operating Instruction is focused on real-time activities necessary to preserve the real-time status and condition of the BES and indicates that such activities may only be issued by operating personnel responsible for the Real-time operation of the BES, ERCOT suggests that the use of the term Operating Instruction within the multiple time horizons referenced throughout IRO-001-4 (especially the operations

Organization	Yes or No	Question 1 Comments
		planning and same-day operations time horizons) undermines the objectives of issuing Operating Instructions in Real-Time, are likely to cause confusion regarding the Operating Instruction an entity should implement, and would result in significant resource and operational concerns. First, because the term Operating Instruction as developed and utilized in COM-002-4 is intended to provide operating personnel responsible for the real-time status and condition of the BES with additional tools and authority to prevent miscommunications and ensure the reliability of the BES, its definition has been tailored to real-time scenarios and responsibilities. Indeed, the very definition is focused on responding to emerging conditions within the BES to ensure reliability, connoting urgency and ensuring that the issuer's authority and direction is unchallenged and timely implemented. This sense of urgency and authority that provided additional strength to Reliability Coordinators in fulfilling obligations under COM-002-4 is weakened significantly when the term Operating Instruction is applied to activities expected to be performed days in advance of target operating day. Specifically, because the activities identified as mitigations to forecasted system conditions are based on forecasts and best available information in advance of the actual operating day, such conditions may never manifest themselves and the "command" issued may never need to be implemented. Accordingly, the use of the term Operating Instruction within Same-Day and Operations Planning Horizons is likely to cause confusion as the directed activities may never need to be taken, but would essentially be defined through the use of the term Operating Instructions, as "urgent" actions. Additionally, entities being issued advance "Operating Instructions" may become confused regarding what activities they should perform if Operating Instructions devised as a result of a Next-Day Study differed from the Operating Instructions received in Real-Time. Generally, actions in advance of the target operating day are coordinated amongst impacted entities with the objective of ensuring that operating parameters are respected should adverse conditions manifest during the target operating day. These activities are generally plans that are developed prior to the target operating day in response to forecasted conditions. As discussed earlier, the term Operating Instruction was devised to provide Reliability Coordinators and other responsible entities with the tools and authority necessary to

Organization	Yes or No	Question 1 Comments
		proactively ensure the reliability of the BES in real-time. Plans developed in response to forecasted conditions that may or may not manifest themselves are not and should not equated with actions that should be taken immediately to preserve reliability. Finally, ERCOT notes potential resource and operational concerns with requiring Reliability Coordinators to utilize their operating personnel responsible for Real-time activities to issue Operating Instructions that would result from Operational Planning Analyses conducted well in advance of real-time. In particular, because the definition of Operating Instruction requires that such an instruction be issued by operating personnel responsible for the real-time operation of the BES (which is generally interpreted synonymously with “system operator”), ERCOT respectfully submits its significant concerns regarding diverting its real-time personnel and resources to tasks generally performed by personnel focused on the day-ahead or operations planning time horizons. More specifically, Operational Planning Analyses are generally performed by personnel that are not considered operating personnel, but are, rather Operations Support Personnel or other technical personnel. The review, analysis, and final decisions regarding necessary actions, while coordinated with operating personnel, are generally completed and communicated by those same personnel. To issue Operating Instructions for analyses performed in the forward planning horizons would require diversion of operating personnel from their primary tasks in the real-time environment to tasks generally performed by personnel focused on operations planning. ERCOT respectfully submits that such would not only cause resource concerns by diverting real-time personnel from ensuring the reliability of the BES, but would also cause operational concerns as entities receiving such Operating Instructions from personnel that are essentially System Operators may cause confusion regarding when such Operating Instructions should be implemented. To resolve the foregoing concerns, ERCOT respectfully suggests that the Standards Drafting Team (SDT) insert the term “directive” or other verbiage where the use of Operating Instruction is intended to address multiple time horizons until the definition of operating instruction is modified or - should such modification not be possible -permanently (e.g., IRO-001-4, R1, R2, and R3) and coordinated with COM-002-4. As it stands today, applying the term to more than the Real Time horizon will likewise expand the scope of

Organization	Yes or No	Question 1 Comments
		communications that must be addressed in COM-002-4 R1-R3.R1. Each Reliability Coordinator shall act, or direct others to act, by issuing directives or Operating Instructions, to ensure the reliability of its Reliability Coordinator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] 2. To ensure consistency amongst requirements within the IRO-001-4 standard, it is recommended that Requirement R3 be revised to more closely reflect its triggering or immediately preceding requirement, Requirement R2. The proposed Requirement R3 would read: R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition that the Operating Instruction issued by its Reliability Coordinator pursuant to Requirement 1 cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Additionally, it is recommended that the associated VSL also be modified accordingly.
Response: 1. The SDT agrees with the comments regarding the Operations Planning Horizon and has deleted this horizon from all requirements dealing with Operating Instructions. 2. The SDT believes the current wording in Requirement R3, based on changes made from previous industry comments, clearly states the requirement to inform the Reliability Coordinator if an Operating Instruction cannot be performed. The SDT does not believe the suggested change adds clarity. No change made.		
Associated Electric Cooperative, Inc. - JRO00088 SPP Standards Review Group Kansas City Power & Light	No	AECI agrees with SPP comments regarding R1-R3: R1 - We have concerns regarding the phrase ‘to ensure the reliability’. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Reliability Coordinator takes action or directs others to act. Additionally, we suggest tying the ‘others’ in Requirement R1 specifically to those entities identified in Requirements R2 and R3.We recommend the following rewrite: ’Each Reliability Coordinator shall act, or direct others as identified in Requirements R2 and R3 to act, by issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.

Organization	Yes or No	Question 1 Comments
		'Rationale Box for Requirements R2 & R3 - The Rationale Box for Requirements R2 and R3 does not match the language in the requirements. There is no mention of the Transmission Service Provider in the requirements. It only appears in Measures M2 and M3. The IRO Five Year Review Team had recommended adding Transmission Service Provider to Requirements R2 and R3 to allow the retirement of IRO-004-2. With the removal of the Transmission Service Provider in Requirements R2 and R3, can the retirement of IRO-004-2 move forward?
Response: 1. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. 2. The SDT agrees and has corrected the language in the rationale box.		
Ingleside Cogeneration , LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in IRO-001-4 R2 and R3. In R2/R3, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on IRO-001-4's requirements to execute an Operating Instruction - and not so much COM-002-4's oversight of the protocols to use. However, an Operating Instruction can be any communication to "change or preserve the state, status, output, or input" of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to IRO-001-4, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with "this is a mandatory Operating Instruction" should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount

Organization	Yes or No	Question 1 Comments
		of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome - particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.
Response: The SDT believes that complying with Operating Instructions is extremely important for the reliability of the system and that emphasis in audits will be on whether the Operating Instruction was followed as opposed to a missing log entry. The SDT suggests that the commenter's points would be better submitted as comments on the RSAW for proposed IRO-001-4. No change made.		
Flathead Electric Cooperative, Inc.	No	Measures are improved with not having to cite a reason specifically, but still too much evidence burden on the receiving entity. The BA should have recordings already and some of these evidence requirements are duplicative.
Response: The measures provide examples of evidence that may be used to show an entity complied with an Operating Instruction from its Reliability Coordinator. The entity chooses what evidence to provide. No change made.		
Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: "Each Reliability Coordinator shall issue Operating Instructions, as necessary, to ensure the reliability of its Reliability Coordinator Area." As written, we believe that every communication involving an RC could be considered an Operating Instruction. For example, If a BA/TOP informs the RC of a loss of unit/tripping of equipment and the measures taken to mitigate the situation. Would an RC be required to give Operating Instructions back to the BA/TOP stemming from an informational conversation? We feel the revision adds clarity that the RC will issue Operating Instructions only when they believe it is warranted. R2: No comments M2: All instances of Transmission Service Provider should be removed from this measure.

Organization	Yes or No	Question 1 Comments
		R3: No comments
Response: R1. The definition of Operating Instruction allows for the discussion of general information and alternatives. The SDT points the commenter to the draft RSAW for proposed IRO-001-4 as the SDT believes it provides clarity on situations that may require the issuance of an Operating Instruction and also may alleviate concerns over the potential administrative impact. The SDT has revised the wording of the requirement to provide clarity. See summary for wording. M2. Transmission Service Provider has been removed from M2. See summary for wording.		
Hydro-Quebec TransEnergie	No	Rationale for R2 and R3 should be modified for consistency with the removal of the TSP. R2 : Replace "compliance with the Operating Instructions" with "they" referring to the instructions. Compliance is not something that can be "physically implemented". Instructions can. Also for consistency with M2: Remove the Transmission Service Provider from the second portion of the measure (2 occurrences) Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Compliance section 1.3 : Remove all occurrences of "Transmission Service Provider". (Would have been best achieved by a "search and replace"...)
Response: The SDT agrees and has corrected the language in the rationale box. The SDT believes the current wording of Requirement R2 is correct as written. No change made. Transmission Service Provider has been removed from Measure M2. See summary for wording.		

Organization	Yes or No	Question 1 Comments
The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. Transmission Service Provider has been removed from Compliance section 1.3.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R3 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Reliability Coordinator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. “Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service provider, and Distribution Provider shall inform its Reliability Coordinator [within the time constraints allocated by the Reliability Coordinator in its notification protocol] of its inability to perform an Operating Instruction...”
Response: The SDT still believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes they cannot implement the instruction(s) for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT agrees that an Operating Instruction may include a timeframe given by the Reliability Coordinator, but defining a generic timeframe is not necessary, or appropriate, for a requirement. No change made.		
New York Independent System Operator (NYISO)	No	SDT should consider the use of the word ensure. We suggest revising the phase to, ‘maintain ensure the reliability...’. This term exists in other parts of this group of standards, please consider the comment for all.
Western Area Power Administration	No	Western has a concern on the use of the word ensure in R1. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the RC didn’t provide instructions that ensured the reliability of its area. We would suggest changing the last portion of the requirement to ‘...... issuing Operating Instructions in accordance with its responsibilities as a Reliability Coordinator within its Reliability Coordinator Area.’

Organization	Yes or No	Question 1 Comments
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.		
CenterPoint Energy Houston Electric LLC	No	See comment for TOP-001-3, R1
Response: See response to TOP-001-3.		
BC Hydro	No	The new Requirement has the Reliability Coordinator issuing "Operating Instructions" rather than "Reliability Directives". The scope of "Operating Instructions" broadens to non-emergency situations. BC Hydro does not support this increase in scope.
Response: The SDT believes the use of Operating Instruction is responsive to concerns raised by FERC in the NOPR**.** The SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. Proposed COM-002-4 (pending regulatory approval) was approved by the Board. No change made.		
Northeast Power Coordinating Council	No	The Purpose of IRO-004-4 is: "To establish the responsibility of Reliability Coordinators to act or direct others to act." The Functional Model states that Reliability Coordinators interact with Transmission Service Providers, and Transmission Service Providers interact with Reliability Coordinators. Why is the TSP being removed from the Applicability and the Requirements? The contents of the Rationale boxes need to be reviewed and revised. For example, The Rationale under Applicability mentions Purchasing-Selling Entity and Load-Serving Entity being deleted from IRO-001-1.1. The Rationale for Requirements R2 and R3 mentions the retirement of IRO-004-2. The Rationale for IRO-001-4 should deal with IRO-001-4. The Drafting Team should consider the removal of the Rationale Box for R2 and R3.

Organization	Yes or No	Question 1 Comments
		Suggest that the Drafting Team consider replacing the word “ensure” where used in the Requirements and Measures and VSL Table with the word “maintain”. Because Transmission Service Provider is being removed from the Applicability of the standard, Transmission Service Provider needs to be removed from the body of the standard. For example, the Quality Review did not catch its use in the Data Retention section.
Hydro One	Yes	Agree with same comments as NPCC-RSC
Response: Transmission Service Providers are not listed in the Functional Model for corrective actions issued by the Reliability Coordinator, therefore they would not receive an Operating Instruction from a Reliability Coordinator. These rationale boxes are meant to provide clarity for deletions/retirements made by the SDT. However, based on comments from others, the SDT has corrected the language in the rationale box for Requirements R2 and R3. The SDT has revised the requirement to delete ‘ensure’ and replace it with ‘address’ as in the first posting. See summary for wording. Transmission Service Provider has been removed from Measure M2 and the Compliance section. See summary for wording.		
Colorado Springs Utilities	No	We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following were the comments that we had in addition to SPP's comments. CSU references our previous comments again as we do not feel they were addressed correctly. 1. In R6 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. 2. In R8 there should be a timeframe requirement that the RC needs to adhere to in notifying impacted entities. The response by the SDT referenced other requirements that require notification in other standards stating that the time requirements are covered under those requirements. The requirements referenced by the SDT do require notification at the time of an actual SOL or IROL etc. IRO-001-4 is the pre-contingency analysis that needs to be communicated. We do not feel that the

Organization	Yes or No	Question 1 Comments
		requirements referenced by the SDT cover the pre-contingency analysis required to be communicated by IRO-001-4.
Response: The SDT believes the reference should be for proposed TOP-001-3 and points the commenter to question 7.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	See VSL comments in response to question #11 below.
Response: See response to q11.		
FRCC Operating Committee (Member Services) City of Tallahassee, TAL	Yes	The groups represented by the FRCC Operating Committee support IRO-001-4 revisions in principle, however we seek clarification on the potential interpretations of the term "Operating Instructions" and the potential administrative impact to normal and emergency BES operations needed to demonstrate compliance as stipulated in the Measures.
Response: The SDT points the commenter to the draft RSAW for proposed IRO-001-4 as the SDT believes it provides clarity on situations that may require the issuance of an Operating Instruction and also may alleviate concerns over the potential administrative impact.		
Tri-State Generation and Transmission Association, Inc.	Yes	There are still mentions of the "Transmission Service Provider" even though it has been removed as an applicable entity. It is mentioned twice in Measure M2 and once again under the compliance section "1.3 Data Retention." All references to the Transmission Service Provider should be removed.

Organization	Yes or No	Question 1 Comments
Response: Transmission Service Provider has been removed from Measure M2 and the Compliance section. See summary for wording.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
NERC Compliance Policy	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comments
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Tennessee Valley Authority	Yes	
Ameren	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
MidAmerican Energy Company	Yes	

Organization	Yes or No	Question 1 Comments
Response: Thank you for your support.		

2. **Do you agree with the changes made to respond to industry comments to proposed IRO-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes**.

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Organization	Yes or No	Question 2 Comments
ACES Standards Collaborators	No	(1) We appreciate the drafting team's consideration of previous comments and subsequent revisions. (2) We recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirements. (3) Requirement R3 is problematic as written because it implies that sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100

Organization	Yes or No	Question 2 Comments
		kV facilities are needed for reliability they would be part of the BES exception process and would be covered by the NERC defined term “Facilities.” The FERC NOPR that proposed to remand the TOP/IRO standards was issued on November 21, 2013, which was prior to the BES definition coming into effect on July 1, 2014. This is a significant justification to remove the sub-100 kV language. (4) We recommend verifying that the redlined and clean copies of the draft standard have consistent numbering of the requirements. When R1 was deleted in the redlined version, the other requirements did not reflect this change. Considering there are over 30 documents to review with this posting, it can be confusing when the requirements do not match.
Response: (1). Thank you for your support. (2). Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term and approved by FERC then a project will be undertaken to make the necessary corrections throughout these standards. No change made. (3) Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-001-3, TOP-003-3, and IRO-010-2. See summary for wording. (4) The SDT is making every effort to align the requirement numbering.		
Electric Reliability Council of Texas, Inc.	No	1. ERCOT respectfully submits that Requirement R1 is duplicative to COM-001, R1 and recommends that it remain deleted. 2. ERCOT respectfully suggests that Requirement R2 requires clarification regarding the entities with which a Reliability Coordinator shall have data exchange capabilities and what shall constitute such data exchange capabilities as some information sharing does not lend itself to data links. The following revisions are proposed: R2. Each Reliability Coordinator shall exchange data with Balancing Authorities,

Organization	Yes or No	Question 2 Comments
		Transmission Operators, and other entities as identified in the data specification developed and maintained in accordance with IRO-010 and necessary to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. [Violation Risk Factor: High] 3. ERCOT respectfully suggests that Requirement R3 may be confusing and redundant as written and proposes a streamlined, less ambiguous version for the SDT's consideration. The following revisions are proposed: R3. Each Reliability Coordinator shall monitor the Facilities, status of Special Protection Systems, and sub-100 kV facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas that are necessary to identify System Operating Limit exceedances and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Response: 1. Requirement R1 will remain deleted. 2. The SDT feels this requirement is clear as to entities the Reliability Coordinator deems it needs data exchange capabilities with and what purpose those data exchange capabilities would serve. No change made. 3. The SDT does not believe that the suggested change adds clarity. However, due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.		
Associated Electric Cooperative, Inc. - JRO00088	No	R2: The OC Review Group suggests adding the word 'its' between 'with' and 'Balancing Authorities' to provide clarity. Suggested Wording: "R2: Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments."
Response: The SDT agrees and has made this non-substantive change. See summary for wording.		

Organization	Yes or No	Question 2 Comments
Hydro-Quebec TransEnergie	No	Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).
Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made.		
Dominion Compliance Policy	No	Dominion does not agree with R3, of the "clean version," as written. We are opposed to the inclusion of the phrase "including sub-100 kV facilities". We would prefer to modify the requirement to read "Each Reliability Coordinator shall monitor BES Facilities, including sub-100 kV facilities and the status of Special Protection Systems within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, to ensure that it is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area." It is our position that any relevant sub-100 kV facility should be included as a BES Facility through the BES Exception process. While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated. M1 as written, "...and real-time Assessments." the word "Real" needs to be capitalized.
Response: Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.		

Organization	Yes or No	Question 2 Comments
The measure has been corrected.		
SPP Standards Review Group Colorado Springs Utilities	No	M1 - Capitalize Real-time in the last line of Measure M1.
Kansas City Power & Light	No	M1 - Capitalize Real-time in the last line of Measure M1.
Response: The measure has been corrected.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU's etc.) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comments</th></tr>
<tr><td></td><td></td><td>performed in the space of 30 minutes and may not keep pace with changing real-time conditions.

The language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the “authority to approve” doesn’t literally mean the same thing as “work shall not be performed without RC approval.” The latter appears to be what the SDT intends, but the language does not appear to support it.</td></tr>
<tr><td colspan="3">Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of phase angles.   For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term ‘applicable’ was intended to capture that intent and to protect an entity against unreasonable expectations. No change made.

It is the SDT’s intent that the System Operator has the authority to approve, deny, or cancel any outage affecting their ability to communicate, monitor, and analyze the system. No change made.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>R1: Duke Energy suggests the following revision: ”Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.” We believe adding “its BA and TOP” narrows the scope of data sharing required by the RC. We believe the intent should be to ensure the RC has data sharing capabilities with the BAs and TOPs in its RC area and with other entities that the RC believes are needed for performing Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R2:   No comment</td></tr>
</table>

Organization	Yes or No	Question 2 Comments
		R3: Duke Energy suggests the following rewording: ”Each Reliability Coordinator shall monitor identified Facilities, status of Special Protection Systems, and sub-100 kV facilities necessary to identify any System Operating Limit exceedances, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Are a." We believe this rewording provides more clarity on the intent of this requirement. R4: Duke Energy suggest the following language: ”Each Reliability Coordinator shall have Energy Management Systems and SCADA data that provides information utilized by the Reliability Coordinator’s System Operator over a redundant infrastructure.” We feel the language “as written” is too broad. We feel this revision helps remove the perceived vagueness when referring to “monitoring systems”. Also, in regards to “redundant infrastructure”, we ask the SDT the following question: If an entity has redundant capability of its EMS system and one leg of that system is rendered unavailable during a planned or unplanned outage, is the RC non-compliant? In this example, the RC will not be on a redundant system due to the outage. We have concerns that the language as written in the standard would render the RC non-compliant.

Response: R1. The SDT agrees and has made this non-substantive change. See summary for wording.

R3. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.

R4. It is not the SDT’s intent to require entities to have specific tools or systems or to dictate which software tools or systems an entity has to have to perform the function described in the requirement. No change made.

Organization	Yes or No	Question 2 Comments
The purpose of redundancy is to protect against a single point of failure. Specific questions on compliance need to be submitted to NERC Compliance.		
NV Energy	No	The changes made to R2 and R5 are responsive to our prior concerns. However, the language of R3 continues to be imprecise with regard to the requirement that an RC Operator approve each and every planned outage or maintenance of monitoring and analysis capabilities. Merely having the “authority to approve” doesn’t literally mean the same thing as “work shall not be performed without RC approval.” The latter appears to be what the SDT intends, but the language does not appear to support it.
Response: It is the SDT’s intent that the System Operator has the authority to approve, deny, or cancel any outage affecting their ability to communicate, monitor, and analyze the system. No change made.		
Northeast Power Coordinating Council Hydro One New York Independent System Operator (NYISO)	No	The contents of the Rationale boxes must be reviewed with respect to their applicability to IRO-002-4. The Drafting Team should clarify and coordinate the requirements between voice and data equipment requirements and the associated COM-001 and IRO-002-4. The SDT should clarify the COM-001 is restricted to voice communications and the IRO-002-4 R1 is intended to address data. It is also not clear that IRO-002-4 R2 is limited to voice communication and/or data. A wording change for R2 to be considered: Each Reliability coordinator shall have the authority to approve planned outages and maintenance of its telecommunication and data exchange capabilities (as referenced in R1). Requirement R3 has had the word “telecommunication” added to it. Should also add the word telemetering to make the requirement read “...telecommunication and telemetering...”. Then use of telecommunication and telemetering should be made consistent throughout the document. In Requirement R4 delete the comma between “...Special Protection Systems, and sub-100kV...” to make it read “...Special Protection Systems and sub-100kV...”. This

Organization	Yes or No	Question 2 Comments
		makes it clear that both Special Protection Systems and sub-100kV facilities shall be monitored.
Response: The SDT agrees and has corrected the language in the rationale box. The SDT does not believe that the suggested change adds clarity. No change made. The SDT believes that the commenter is referring to Requirement R2. The wording in Requirement R2 is consistent with the wording in proposed TOP-001-3 Requirement R16. No change made. The SDT does not believe that the suggested change adds clarity. No change made.		
FRCC Operating Committee (Member Services) City of Tallahassee	Yes	However, R5 requires "synchronized information systems". The FRCC Operating Committee seeks clarification from the drafting team on what constitutes a "synchronized information system". Consider replacing the word "synchronized" with "coordinated."
Response: The SDT believes that the commenter is referring to Requirement R4. The SDT believes that a 'synchronized' information system is adequately characterized by the dictionary definition of "cause to occur or operate at the same time or rate". The SDT sees no additional clarity being provided by the suggested change. No change made.		
MRO NERC Standards Review Forum	Yes	Please see question 7.
Response: Please see response to q7.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	Yes	R4 begins with 'Each Reliability Coordinator shall monitor Facilities...' Southern suggest that the words, "Bulk Electric System" be added to R4 so that it reads 'Each Reliability Coordinator shall monitor "Bulk Electric System Facilities", consistent with the verbiage in IRO-003-2 Requirement 1. Measure 4 should also be changed accordingly. R4 - Southern suggest that utilization of the words, "as necessary" makes the requirement confusing and proposes the below verbiage to add clarity: 'Each

Organization	Yes or No	Question 2 Comments
Generation and Energy Marketing		Reliability Coordinator shall monitor "Bulk Electric System Facilities", the status of Special Protection Systems, and sub-100 kV facilities identified by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas, "as being necessary to determine" any System Operating Limit (SOL) exceedances within its Reliability Coordinator Area.' Changes would apply to Measure 4 as well.
Response: R4. The use of the defined term 'Facilities' means that it is BES and the suggested change would thus be redundant. No change made. The SDT feels the language as written communicates the correct intent. No change made.		
Texas Reliability Entity	Yes	Requirement R4: Texas Reliability Entity, Inc. (Texas RE) requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality.
Response: Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording.		
Florida Municipal Power Agency	Yes	The previous suggestion from the FRCC Operating committee was not taken regarding the "to approve" language in R3. As drafted this does not cover the full spectrum of authority needed by the RC. FMPA suggests replacing the words "to

Organization	Yes or No	Question 2 Comments
		approve" with "over" to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators.
Response: The SDT believes the Requirement language captures the SDT's intent of full authority to approve, deny, cancel, etc., planned outages. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	

Organization	Yes or No	Question 2 Comments
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

3. **Do you agree with the changes made to respond to industry comments to proposed IRO-008-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes to the requirements based on industry comments:

Rationale Box for Requirements R2 and R3: Requirements added ~~I~~in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.)

R3. Each Reliability Coordinator shall notify impacted entities identified in its ~~the~~ Operating Plan(s) cited in Requirement R2 as to their role in ~~those~~ such plan(s).

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~ Wide Area.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 has been prevented or mitigated.

Organization	Yes or No	Question 3 Comments
Texas Reliability Entity	No	1) Requirement R1: The SDT changed “or” to “and” within the phrase “System Operating Limits (SOLs) or Interconnection Operating Reliability Limits (IROLS)” based on a comment. Neither the commenter nor the SDT provided justification for the change. Texas RE does not agree with the change because if either SOLs OR IROLs are exceeded then the assessment should be performed; not just if both are exceeded. Texas RE requests that the change be rejected and the original language be reinstated or explanation of why the change is correct. 2) Section 1.3. Data Retention: Texas RE does not agree with the change of data retention for R1, R2, R3, R5 and R6 from a rolling six months to a rolling 90 calendar days. The six-month requirement was aligned with the Data Retention and Sampling Team (DRAST) white paper, which indicates a six-month rolling period for high volume

Organization	Yes or No	Question 3 Comments
		data, and 90-days for voice and audio recordings. The same comment applies for R4, which was changed from 90 days to a rolling 30 days.
Response: 1) The SDT believes that the proper term here is 'and'. Using 'or' leaves the requirement open to an interpretation where either SOLs or IROLs would need to be assessed. Both need to be assessed therefore justifying the use of 'and'. No change made. 2) The SDT believes that the requirements associated with an Operating Plan for next-day operations qualifies as a high volume task and could create a documentation burden on the part of the Reliability Coordinator. To reduce this compliance burden the data retention period was reduced. A similar argument applies to Requirement R4. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. ERCOT respectfully submits that Requirement R3 is ambiguous as written. More specifically, the use of terms such as "coordinated" and "considered" are undefined and unnecessarily complicate Reliability Coordinator's responsibilities and documentation. In R2-R3, the current definition of Operating Plan states "a document". While this context is appropriate for processes/procedures determined well in advance of real time (e.g. EOP 005, EOP 008). The timeframe described is really next day and while most "Operating Plans" are documented, all plans to operate reliably may not be documented or in "a document". The definition should be modified to address this new usage of the term to make it appropriate for all its uses, or a different term should be used. In its current form, it may lead to unnecessary administrative violations due to the lack of having "a document" rather than operations being coordinated and have a plan to operate reliably. The plan can be still coordinated but exist in various systems and conversations/emails/documents. This presents similar challenges for R4 as well as it further infers a single "document" and have several required elements. This can be overly prescriptive and burdensome. 2. ERCOT respectfully submits that Requirement R4 is ambiguous as written. More specifically, it is unclear as to whether the Reliability Coordinator is responsible for notification of those entities impacted in its Operating Plan or all Operating Plans referenced in Requirement R3. 3. ERCOT suggests that the SDT review the language of Requirement R5 and its VSL for consistency. In particular, Requirement R5 was modified to require that the Reliability

Organization	Yes or No	Question 3 Comments
		Coordinator ensure that a Real-Time Assessment is performed every 30 minutes. However, the VSL still assesses the condition that the Reliability Coordinator did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. These should be reviewed and revised to ensure consistency between the requirement and its VSL. 4. ERCOT respectfully notes that Requirement R5 and the associated VSLs do not acknowledge the necessary tool outages that occur as part of planned system maintenance to ensure that Reliability Coordinator tools continue to run with high availability and accuracy. With the continuing obligations of Registered Entities to ensure the cybersecurity of their tools and the clear acknowledgment of the need for planned outages of Reliability Coordinator tools in IRO-002-4, R3, the current Requirement R5 and the associated VSLs create conflict and inconsistency amongst the overall set of Reliability Standards. If Registered Entities (and Reliability Coordinators in particular) are required to maintain their analysis tools, which maintenance may require outages of such tools, Requirement R5 should not provide that Reliability Coordinators will be penalized for the very activities they are required to conduct under its obligations set forth within the overall set of enforceable Reliability Standards. More clearly stated, it should not be a violation if an entity has a planned tool outage that causes a reasonable time deviation from the normal 30 minute timeframe. The following revisions are proposed are proposed to address this inconsistency: R5. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes except where performance is delayed as a result of a planned or unplanned tool outage and potential effects of the delay are mitigated where possible. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations] It is further recommended that the associated VSLs also be modified accordingly. 5. ERCOT has identified a potential typographical error in R6 and all of its VSLs. Specifically, the reference to "as identified in identified in Requirement R6" should likely be reviewed and revised to "as identified in Requirement R5".

Organization	Yes or No	Question 3 Comments
		6. ERCOT respectfully reiterates its previous comment on the inconsistent language used between Requirements R5 and R6 and the LOWER VSL for Requirement R8. In particular, the word "Emergency" is used in the VSL for Requirement R8 but the condition is not specified elsewhere in the standard or the appropriate referenced requirements. Please revise the lower VSL for Requirement R8 to ensure consistency. The following language is proposed: "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated". 7. The reference in Requirements R6 and R8 to "as indicated in its Operating Plan" is unnecessary and only creates additional compliance burden. Operating conditions can change very quickly and can cause a "plan" to vary and the impacted entities to vary. The phrase "as indicated in its Operating Plan" should be deleted. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of "Operating Plan" and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.

Response: 1. The SDT believes the commenter is referring to the new Requirement R2 (old Requirement R3). A Reliability Coordinator develops its Operating Plan by reviewing the results of its Operational Planning Analysis while taking into consideration the Operating Plans of the Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. The outcome is a coordinated plan for next-day operations. No change made.

2. The SDT believes the commenter is referring to the new Requirement R3 (old Requirement R4). The SDT concurs with your concern and has modified Requirement R3 as found in the Summary Comments above.

3. VSL responses are handled in q11.

4. IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on

Organization	Yes or No	Question 3 Comments
to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. 5. The SDT agrees and has corrected the typo. See summary for corrected requirement. VSL responses are handled in q11. 6. VSL responses are handled in q11. 7. The phrase was inserted to require the Reliability Coordinator to only notify those other Reliability Coordinators that are impacted by the Reliability Coordinator's Operating Plan. Otherwise, the Reliability Coordinator would have to notify all other Reliability Coordinators since they would all be impacted, some more than others. No change made. 8. The additional explanation under Associated Documents was provided to further enhance and clarify the definition. The SDT felt that this was a more effective and efficient way to provide this rather than incorporating it into the definition and creating a voluminous definition. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	1.3 Data Retention - Hyphenate 30- and 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Response: The SDT agrees and has made the indicated corrections.		
IRC Standards Review Committee Independent Electricity System Operator	No	a. R6 and all of its VSL: The reference to "as identified in identified in Requirement R6" should be revised to "as identified in identified in Requirement R5". b. We wish to reiterate our previous comment on the inconsistent language used between Requirement R6 (was R8 but misquoted in our previous comment as R6) and the LOWER VSL for R6 in which the word "Emergency" is used but the condition is not specified in R6.R6 stipulates that: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated.

Organization	Yes or No	Question 3 Comments
		However, the LOWER VSL for R6 indicates that: The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan “when the Emergency identified in Requirement R6 was prevented or mitigated.” Please revise VSL to read “when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated” as opposed to “Emergency” for consistency. c. The language between R4 and its VSL is inconsistent.R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC to “perform” to “ensure that” a Real-time Assessment is performed. However, the VSL still assesses the condition that the RC did not “perform” as opposed to did not “ensure that” the Real-time Assessment was performed. Please revise as appropriate.
Response: The SDT agrees and has corrected the typo. See summary for corrected requirement. VSL responses are handled in q11. b. and c. VSL responses are handled in Question 11.		
Northeast Power Coordinating Council Hydro One	No	“Ensure” or “ensured” should not be used in the standard. The contents of the Rationale boxes must be reviewed to ensure they are consistent with their associated Requirements. For example, the Rationale for Requirements R5 and R6 refers to the use of the word “impacted”. Impacted is not used in Requirement R5. The contents of the Rationale for R1, and R3 and R4 should be expanded to provide a short background statement for the Rationale. The wording of requirements should be made consistent. Why is Requirement R7 being deleted?
Response: The SDT has reviewed the use of ‘ensure’ throughout the standard and believes that the use of the term in this standard is correct. No change made.		

Organization	Yes or No	Question 3 Comments
Please refer to the clean version of the standard. The new Requirements R5 and R6 contain 'impacted'. Granted, the requirement numbers in the redline version did not align with the references in the Rationale Boxes which has now been corrected. . SOLs were included in Requirement R1 as a result of a concern expressed by FERC in paragraph 96 of the NOPR. Likewise, Requirements R2 and R3 were added to address concerns expressed in the SW Outage Report and by the Independent Expert Review Panel. Additional wording has been included in the Rationale Box for Requirements R2 and R3. The SDT decided to delete Requirement R7 because it is redundant with the more generic proposed IRO-001-4, Requirement R1.		
Associated Electric Cooperative, Inc. - JRO00088 South Carolina Electric and Gas	No	In R5, suggest expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In R8, the OC Review Group suggests removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs. Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated."
Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the		

Organization	Yes or No	Question 3 Comments
Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Georgia Transmission Corporation	No	In R5, suggest expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In R8, suggest removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs. Suggested Wording: "R8: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated."
Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Consumers Energy Company	No	I have a concern with the evidence for compliance with Requirement 4. The Standard as written does not clearly define parties who must be notified. The reference to the Operations Plan does not require the inclusion of any non-registered entity.

Organization	Yes or No	Question 3 Comments
Response: New Requirement R3 (old Requirement R4) indicates that the Reliability Coordinator must notify those entities that it determined were impacted in its Operating Plan which is based on its Operational Planning Analysis as conducted in Requirement R1. The SDT has made clarifying changes to Requirement R3 which should alleviate your concern. See the Summary Consideration.		
Dominion Compliance Policy	No	In R8, Dominion suggests removing the words 'prevented or' because prevention of SOL or IROL exceedance is difficult to prove and would typically not be communicated to BAs and TOPs.
Response: Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Florida Municipal Power Agency	No	It seems the SDT did not understand FMPA's previous comment regarding R1. FMPA's comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase "N-1 Contingency planning" no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the RC's OPA supposed to consider N-2 events? N-3? Loss of an entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs and IROLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase "in accordance with its SOL Methodology". Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards. The number of contingencies to be studied is also absent from the definition of Real-time Assessment.

Organization	Yes or No	Question 3 Comments
Response: The SDT does not want to be overly prescriptive. The Transmission Operator has the obligation to preserve the reliability of the interconnected Transmission system. The Contingencies to be handled in an Operational Planning Analysis are laid out in the Reliability Coordinator's SOL methodology and the SDT expects that an entity will adhere to that methodology when performing its Operational Planning Analysis. No change made.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU's etc.) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions.

Organization	Yes or No	Question 3 Comments
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made.		
Duke Energy	No	R1: No Comment R2: No Comment R3: No Comment R4: No Comment R5: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an RC's Energy Management System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R6: We believe the incorrect requirement was referenced in R6. The phrase should be as follows :"when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated." Please change the reference of "R6" with "R5" as seen in the example above. R8: Duke Energy suggests the following revision: "Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been mitigated." We suggest removing "prevented" because the prevention of SOL/IROL

Organization	Yes or No	Question 3 Comments
		exceedances will be difficult to prove and would not typically be communicated to BAs and TOPs. The communication activities should be restricted to communications of activities to mitigate a potential SOL/IROL exceedance and not the prevention.
Response: Requirement R5 (new Requirement R4) – Approved IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Requirement R4 in proposed IRO-008-2 does not add or detract from that requirement. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. Requirement R6 (new Requirement R5) – The SDT agrees and has corrected the typo. See the Summary Consideration for the corrected requirement. VSL responses are handled in Question 11. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates an actual or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R4 - It is not clear why the SDT removed the qualifier "NERC registered". Southern recommends adding "NERC registered" back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. In addition, Southern noted that the SDT responded with the following comment in consideration of comments received for R4."Impacted goes beyond the concept of those entities that have an active role to play in the Operating Plan. It also includes those entities which may not have an active role to play in the plan but are still impacted by the given operating condition. For example, an entity may have Load impacted by a given situation and the only available option that entity may have is to shed that Load. But if the plan doesn't call for that entity to shed the Load, then the entity doesn't have an active role in the plan but is still impacted by the situation and therefore is deserving of notification." It is

Organization	Yes or No	Question 3 Comments
		very unclear on what expectation the SDT is suggesting in this comment. If the RC conducts a next day study and identifies potential issues, the RC will develop a plan to resolve the issue. This plan will be communicated to the NERC registered entity that is responsible for implementing the plan. The example provided by the SDT is unclear and confusing in that it introduces an entity that was never part of the plan to resolve the issue. If this entity was never part of the plan, why would or should the RC notify such entity? R8 - Southern suggests modifying R8 as follows (include “actual”) to require notification in the event of an actual SOL or IROL exceedance within the RC area, but not require notification in the case where there was a possible SOL/IROL exceedance, but system conditions changed that cause the potential issue to subside. Southern believes that requiring notification for the latter is a good utility practice, but does not maintain or enhance reliability as it is nothing more than a notification that “nothing is required any longer for what could have been ”Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. [Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations] Southern also recommends moving the word “known” in the definition of Operational Planning Analysis to the beginning of the second sentence to reflect that the evaluation shall reflect applicable “known” inputs. The “known” should apply to each of the inputs and not just Protection Systems and SPS status and degradation. The Operational Planning Analysis should reflect what the TOP knows at the time the evaluation is conducted. TOPs continue to update the studies as updated or “known” information becomes available. See suggested revision below. Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable known inputs including, but not limited to, load

Organization	Yes or No	Question 3 Comments
		forecasts; generation output levels; Interchange; Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Response: Requirement R4 (new Requirement R3) – There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. In the referenced example, the impacted Load may only suffer the consequences of the operational condition and still not play an active role in the mitigation of that condition. If for example, the Load is suffering from low voltage and its Distribution Provider has done everything it can do to alleviate the situation short of shedding Load, the plan could call on other entities identified in the plan to take action to assist in relieving the under-voltage situation such that Load would not have to be shed. Since its Load is on the line, the Distribution Provider should be notified of the potential for the condition and then notified when that threat is mitigated. No change made. Requirement R8 (new Requirement R6) – Requirement R5 requires the Reliability Coordinator to notify impacted entities whenever its analysis indicates a real or expected exceedance of an SOL or IROL occurs. Notification of a potential exceedance will set in motion a process to either mitigate the SOL/IROL before it occurs or after it actually occurs. If that operating condition no longer exists, the Reliability Coordinator must follow through with a 'stand down' notification such that those processes are returned to normal. No change made. Operational Planning Analysis – The SDT believes that the definition is worded correctly as stated since it now includes the word 'applicable'. No change made.		
Hydro-Quebec TransEnergie	No	R6: Replace "Reliability Coordinator Wide Area" by "Wide Area" for consistency with modifications made to R1. Compliance section 1.2: What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer

Organization	Yes or No	Question 3 Comments
		to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R4, R6 and R8 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3. Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: Requirement R6 (new Requirement R5) –The SDT agrees and has made the suggested change. See the Summary Consideration. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. VSL responses are handled in Question 11. Associated Documents – It is the normal practice to include this type of clarifying information, including the content of the Rationale Boxes, in this section of the standard. It provides a quick reference, in the standard itself, for further clarification of the requirements. No change made.		
PacifiCorp	No	The implications of removing the term NERC Registered from R4 are unclear because a Planning Coordinator may not be able to rely on information provided by unregistered entities. If the RC in IRO-008-2 M3 creates an Operating plan that includes non-registered Entities (TOP-002-4 R4 clearly shows that NERC thinks that non-registered entities WILL be included in some Operating Plans), the TOP responsibility of TOP-002-4 will only pertain to the NERC registered entities. This creates a serious potential reliability "gap" that must be addressed before this draft can be evaluated.
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those		

Organization	Yes or No	Question 3 Comments
unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
New York Independent System Operator (NYISO)	No	The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes may have been based on the requirements to be within IROL's in 30 minutes. The 30 minute assessment for SOL's may be over prescriptive as some SOL could be up to 4 hours.
Response: The SDT does not agree that this requirement should be limited to IROL evaluations. The FERC NOPR made it clear that Transmission Operators should be performing SOL evaluations as well. The SDT wants to reinforce that a Real-time Assessment does not imply that all identified SOL exceedances need to be resolved within 30 minutes. SOL exceedances need to be mitigated consistent with the Transmission Operator's Operating Plan as highlighted in the SOL Exceedance White Paper. IROL exceedances would need to be mitigated consistent with the IROL T_v. No change made.		
Peak Reliability	Yes	R1 as written requires the RC to perform an OPA to assess whether planned operations will exceed SOLs and IROLs in its Wide Area. NERC defines Wide Area as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits". According to this NERC definition, the Wide Area does not include actual Facilities outside the RC Area, but rather includes flow and status information from adjacent RC Areas for the purposes of IROL calculation (whether the IROL is in the RC Area, in the adjacent RC Area, or spanning across multiple RC Areas). It brings in information from outside the RC Area for IROL calculation - it does not bring in additional Facilities outside the RC Area for general monitoring. Therefore, requiring an OPA to assess SOL and IROL exceedances in a Wide Area actually doesn't make sense, given the fact that the Wide Area does not include actual Facilities outside the RC Area, but rather information from outside the RC Area. Given the NERC definition of Wide Area, the requirement can only make sense if it requires the OPA to assess whether planned operations in its Wide Area (i.e., flows and statuses outside its RC Area for the purposes of IROL calculation) is expected to exceed any of its SOLs and IROLs. Peak

Organization	Yes or No	Question 3 Comments
		believes that the standard should be rephrased to state, "Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations within its Wide Area for the next-day will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs)." With this language change, the flow and status information from the Wide Area are included in the RC's OPA to determine SOL and IROL exceedances appropriately (including IROLs within the RC Area as well as IROLs that span multiple RC Areas).This language change will also bring consistency with its companion requirement TOP-002-4 R1, which states, "Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs)." Peak believes this language change accurately reflects the NERC definition of Wide Area and ensures SOLs and IROLs are addressed appropriately to ensure reliability across the board. R5: It should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.

Response: Requirement R1 – The wording change being proposed limits the Reliability Coordinator's assessment to the SOLs and IROLs only within its Reliability Coordinator Area. This then limits the overall benefit of the Wide Area. If conditions within Reliability Coordinator A's Reliability Coordinator Area create the potential for SOL or IROL exceedances outside its Reliability Coordinator Area, but still within its Wide Area, but those conditions are not within the Wide Area view of neighboring Reliability Coordinator B's Wide Area view, then without notification by Reliability Coordinator A, Reliability Coordinator B would not be aware of the situation. Additionally, the SDT believes that the definition of Wide Area does include knowledge of Facilities within that Wide Area. If not, why would status information be included? A Reliability Coordinator must have those Facilities included in its models in order to factor in the status of those Facilities. Given the gap presented by the proposed language and the belief that Facilities are already properly accounted for; the SDT prefers the original language. No change made.

Requirement R5 (new Requirement R4) – The same evidence would be required regardless of which party actually conducts the assessment. Even though a Reliability Coordinator may delegate that task to a third party, the Reliability Coordinator is still

Organization	Yes or No	Question 3 Comments
accountable from a compliance standpoint. In the situation where a third-party actually performs the assessment, the only additional evidence that may be required is the delegation agreement between the Reliability Coordinator and the third party. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards while generally reducing the compliance documentation burden.
American Transmission Company, LLC	Yes	Although proposed IRO-008-2 is not applicable to ATC, changes were made by the SDT to Requirement R1 and the proposed term “Reliability Coordinator Wide Area” that addressed ATC’s comments in response to the SDT’s 1st posting.
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comments
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

4. **Do you agree with the changes made to respond to industry comments to proposed IRO-010-2? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1, Part 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Organization	Yes or No	Question 4 Comments
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated.
Ingleside Cogeneration , LP	No	ICLP agrees there are times where the RC will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason - and eliminates the possibility that the RC can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of RCs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned RC - that a full evaluation by an independent panel would take place afterwards.
BC Hydro	No	The new Requirement has the Reliability Coordinator able to ask for "sub-100 kV' data if it deems necessary. This is an increase in scope from the data the RC currently asks

Organization	Yes or No	Question 4 Comments
		for. As this data may be outside the BES definition, BC Hydro does not support this increase in scope.
Response: Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
ACES Standards Collaborators Georgia Transmission Corporation	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) We disagree with Requirement R1, part 1.1 that includes sub-100 kV data. The BES definition is very clear to the applicability of standards. IRO-010-2 should apply to BES Facilities, which may include sub-100 kV Elements and Facilities based on a determination from Regional Entity. Asking for non-BES data is out of scope of the jurisdictional bounds of reliability standards.
Response: As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made. Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy does not agree with the structure of R1.2. While Protection System owners generally monitor the status of their Protection Systems CenterPoint Energy is very concerned that the proposed language would require Protection

Organization	Yes or No	Question 4 Comments
CPS Energy		System owners to continuously notify their respective RC of the status of each Protection System which would be a very onerous task with questionable reliability benefit. In addition, for the RC to monitor the status of all Protection Systems in their area would be an overwhelming burden with little reliability benefit. The Company recognizes the need to notify an RC of a Protection System failure that impacts System reliability as required in PRC-001 and therefore recommends Protection Systems and Special Protection Systems be split into separate sub bullets as such: 1.2. Provisions for notification of current Protection System failures that impact System reliability. 1.3. Provisions for notification of current SPS status or degradation that impact System reliability. These comments would also apply to TOP-003-3.
Response: The SDT does not intend for the Reliability Coordinator to monitor Protection Systems rather the intent is for the equipment owner to notify the Reliability Coordinator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. The suggested change is semantic in nature. Both portions of the compound subject are modified by the descriptive prepositional phrase: "…Protection System and Special Protection System status or degradation that impacts System reliability." No change made.		
Duke Energy	No	Duke Energy does not disagree that the types of data exchanges described in this proposed IRO-010 are necessary. However, we believe that these data exchanges currently take place within the context of various existing ERO Requirements and/or various existing agreements between the Applicable Entities. Therefore we do not believe there is a need to codify these requirements in another ERO Standard. As written, this Standard simply creates additional administrative burden on the industry while providing no incremental reliability benefit. As written, Duke Energy believes this Standard would simply become a candidate for a future Paragraph 81 submittal.
Response: This proposed standard is directly responsive to the SW Outage Report Recommendation #3. No change made.		
Hydro-Quebec TransEnergie	No	R1: Replace the last sentence with "The data specification shall include but is not be limited to: Otherwise the "shall" applies to "not be limited to". That would mean that the data specification shall include other items that are not listed.

Organization	Yes or No	Question 4 Comments
		Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Compliance section 1.3 : Remove Planning Coordinator and Transmission Planner Table of Compliance Elements: VSLs for R2 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.
Response: The suggested wording change is semantic in nature and the SDT does not believe it adds clarity. No change made. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. Compliance Section 1.3 – The SDT agrees, and removed Planning Coordinator and Transmission Planner. Interchange Authority was removed in the previous posting. VSL responses are handled in q11.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term “as deemed necessary” in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of “Section 4 - Measurability” of the NERC document titled Acceptance Criteria of a Reliability Standard states “Words and phrases such as “sufficient”, “adequate”, “be ready”, “be prepared”, “consider”, etc. should not be used.” ReliabilityFirst believes the phrase “as deemed necessary” is such a phrase, which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.

Organization	Yes or No	Question 4 Comments
Response: In Requirement R1, Part 1.1, "as deemed necessary" refers to the certain data elements that the Reliability Coordinator decides is needed. This would not be a measurement component of this requirement, since Requirement R1, Part 1.1 requires the publication of a list, which can be objectively measured during an audit. No change made.		
Indiana Municipal Power Agency	No	The use of a documented specification for the data needed by the Reliability Coordinator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instances where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Reliability Coordinator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means Generator Operators in this RC area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.
Response: The ability of the Reliability Coordinator to request and receive the data necessary to preserve reliability is a foundation of coordinated system operations. The suggested change would result in an unmeasurable and non-auditable standard. No change made.		
Electric Reliability Council of Texas, Inc.	No	Thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.

Organization	Yes or No	Question 4 Comments
Response: This data concerning Protection System status is currently collected routinely and data transfer mechanisms are in place. Twelve months is a reasonable time frame to implement Requirement R3. The SDT does not intend for the Reliability Coordinator to monitor Protection Systems rather the intent is for the equipment owner to notify the Reliability Coordinator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. No change made.		
Seattle City Light		SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation. For IRO-101-2, SCL asks that the implementation times be extended from nine and twelve months to eighteen and twenty-four months, because it may take longer than one year to negotiate and implement the necessary data exchange agreements among impacted entities. SCL's recommended implementation language is as follows: Section 5. Proposed Effective Date. Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Organization	Yes or No	Question 4 Comments
Response: Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
Peak Reliability	Yes	IRO-010-2 R1 states, "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." The concern with this language is the limiting nature of the scope of the data specification. The OPA is limited to data for next-day operations. R1 should not confine the RC's data specification to data for its OPA and RTA only, but rather should facilitate the RC to obtain the data it needs to perform its RC functions overall. With the current language, a TOP or BA may be able to claim that they have no compliance obligation to provide the RC with data it needs to perform its reliability functions. Peak recommends that R1 be rewritten to state: "The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its reliability functions." R2 should be updated similarly.
Response: The SDT believes that the current wording allows for a Reliability Coordinator to obtain the data it needs. No change made.		
Texas Reliability Entity	Yes	Requirement R1.1: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality.
Response: The SDT has clarified its intent in revised wording. See summary for wording.		

Organization	Yes or No	Question 4 Comments
Colorado Springs Utilities	Yes	No Comments
South Carolina Electric and Gas	Yes	SCE&G is in agreement with the SERC OC comments.
Northeast Power Coordinating Council	Yes	
Hydro One	Yes	Agree with same comments made by NPCC-RSC
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 4 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comments
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	
Ameren	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
Response: Thank you for your support.		

5. **Do you agree with the changes made to respond to industry comments to proposed IRO-014-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes to the standard based on industry comments:

- **M1.** Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.
- **R5.** Each Reliability Coordinator that ~~identified~~Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.
- **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that ~~identified~~identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
- **Data retention:** Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R3, R4, and R7 ~~and R9~~ and Measures M3, M4, and M7 ~~and M9~~.
- **Data retention:** Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirement~~s~~ R6 ~~and R8~~ and Measure~~s~~ M6 ~~and M8~~.

Organization	Yes or No	Question 5 Comments
Electric Reliability Council of Texas, Inc.	No	1. ERCOT notes that the consolidated set of IRO and TOP Reliability Standards utilize the terms “Wide Area” and “Reliability Coordinator Area”. If these phrases are expected or interpreted to be synonymous, ERCOT suggests use one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion.

Organization	Yes or No	Question 5 Comments
		2. To ensure consistency, ERCOT recommends that, in Requirement R1.6, “provisions for” is removed and the sub-requirement begins with “Periodic”. 3. ERCOT respectfully recommends deletion of Requirement R3 as it is duplicative of IRO-008, Requirements R4 and R6. If the distinguishing factor and reason for inclusion is the acknowledgment of Emergency conditions, ERCOT recommends that such language is added to IRO-008. 4. ERCOT respectfully recommends deletion of Requirement R4 as it has been rendered moot by revisions to Requirement R6 and R7. Specifically, since Requirement R6 requires impacted Reliability Coordinators to implement any action plan developed by the Reliability Coordinator with the emergency and Requirement R7 requires assistance so long as the Reliability Coordinator with the emergency has implemented its emergency procedures, the dictation of operating state by other Reliability Coordinators is unnecessary. 5. ERCOT respectfully recommends deletion of Requirement R5 as it is duplicative of IRO-001-4, Requirement R1. Specifically, since Reliability Coordinators always have primary responsibility and ultimate authority to act when they observe conditions in their area that threaten reliability, disagreement with the Reliability Coordinator’s assessment of the conditions by another entity is of no consequence. However, if the objective is to ensure that Reliability Coordinators assist each other in Emergencies, Requirements R5 and R7 could be eliminated and Requirement R6 could be modified as follows: R6. Each impacted Reliability Coordinator shall implement any actions and/or provide any assistance requested by the Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area unless such actions would violate safety, equipment, regulatory, or statutory requirements. 6. ERCOT respectfully notes that it is unable to discern the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. ERCOT urges the SDT and NERC to conduct a thorough and

Organization	Yes or No	Question 5 Comments
		independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays. 7. ERCOT respectfully recommends that, for consistency, the VSLs for Requirement R2 be modified to remove references to criteria and state that Reliability Coordinator failed to maintain Operating Plans, Processes, or Procedures pursuant to one part of Parts 2.1 - 2.3, two parts of Parts 2.1 - 2.3, and so on. 8. It is recommended that the additional text under Associated Documents be utilized to initiate a modification of the definition of "Operating Plan" and deleted from the standard. Registered Entities should be able to rely upon the official definitions and other associated Reliability Standards to discern their obligations. If the SDT has determined that Registered Entities cannot appropriately discern their responsibilities utilizing approved definitions and standards, such definitions should be evaluated for modification and enhancement.
Response: 1. The definition of ***Wide Area*****:** The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. The definition of ***Reliability Coordinator Area*****:** The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made. 2. The SDT believes **"**provisions" is correct for the idea being expressed. No change made. 3. Requirement R3 speaks to notification of Emergencies. Proposed IRO-008-2 Requirement R4 addresses periodicity of Real-time Assessments and Requirement R6 outlines requirements to act for notification of mitigation of SOL and IROL exceedances identified in the Operating Plan. These are not duplicative. No change made. 4. The SDT does not feel that the suggested change adds to reliability or corrects a defect in the standard and declines to make the suggested change at this time. 5. Proposed IRO-001-4 requirement R1 outlines the method by which Reliability Coordinators will act or direct others to act, i.e., issuing Operating Instructions. Proposed IRO-014-3 Requirement R5 requires development of an action plan. Said action plan may not include any Operating Instructions at all. No change made.		

Organization	Yes or No	Question 5 Comments
6. Data retention for Requirements R3 and R4 has been addressed. See summary for wording. 7. VSL responses are handled in q11. 8. The SDT does not feel that a revised definition of Operating Plan is required. The text included under Associated Document is simply an indication of the SDT's intent as to how it anticipated that Operating Plan would be used with respect to this standard. No change made.		
Independent Electricity System Operator IRC Standards Review Committee New York Independent System Operator (NYISO)	No	a. We generally agree with the changes made to IRO-014-3. However, the replacement of "other" with "adjacent" may leave a reliability gap. For example, the notification of Transmission Loading Relief may require "notification or coordination of actions" by, and can have an impact on, RCs other than just the adjacent RCs. Since the words "may impact" already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word "other" into R1, replacing "adjacent". b. We do not have a preference, but we ask the SDT to review the use of the phrase "Wide Area" in IRO-008-2 (and other IRO standards) and the phrase "Reliability Coordinator Area" in IRO-014-3. If these phrases are expected or interpreted to be synonymous, we suggest using one or the other, but not both, throughout the IRO (and other) standards for consistency and to avoid confusion. c. Retention Period: We are unable to find the data retention period for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors.
Response: a. "Other" was replaced by "adjacent" due to overwhelming response by the industry during the first posting. The SDT believes that notifications concerning Transmission Loading Relief are handled through a separate and distinct mechanism. No change made.		

Organization	Yes or No	Question 5 Comments
b**.** The definition of ***Wide Area*****:** The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. The definition of ***Reliability Coordinator Area*****:** The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made. c. Data retention for Requirements R3 and R4 has been addressed. See summary for wording.		
Hydro-Quebec TransEnergie	No	Compliance section 1.2 : What is the rationale behind that modification? As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. The SDT does not understand the comment as no white paper is included in this standard. No change made.		
Georgia Transmission Corporation South Carolina Electric and Gas	No	In R1.1, suggest adding “as identified in R1” at the end of the sentence to identify the criteria and process being addressed. Suggested Wording: “R1.1: Criteria and processes for notifications as identified in R1.” Suggests adding “may” before “impact adjacent Reliability Coordinator Areas” in M1 to match R1. Suggested Wording: “M1: Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comments</th></tr>
<tr><td></td><td></td><td>shall include dated, current in force documentation with the specified elements, and notes from periodic communications.</td></tr>
<tr><td colspan="3">Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made.

The SDT agrees and has made the suggested change. See summary for wording.</td></tr>
<tr><td>Dominion Compliance Policy</td><td>No</td><td>In R1.1, Dominion suggests adding “as identified in R1” at the end of the sentence to identify the criteria and process being addressed. Suggested Wording: “R1.1: Criteria and processes for notifications as identified in R1.”</td></tr>
<tr><td colspan="3">Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>R1.1 - Duke Energy suggests the following language: ”Criteria and processes for notifications as identified in R1.”This provides the clarity on the specific notifications that are required with adjacent RC(s) as defined in R1.

R2: No Comment

R3: No Comment

R4: No comment

R5: Duke Energy suggests the following revision: “Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.” We believe “identifies” is the appropriate wording.

R6: “Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency,</td></tr>
</table>

Organization	Yes or No	Question 5 Comments
		unless such actions would violate safety, equipment, regulatory, or statutory requirements." We believe "identifies" is the appropriate wording.
Response: As Requirement R1, Part 1.1 is a sub-part of the general requirement, the SDT believes that the suggested change is not necessary. No change made. The SDT agrees and has made the suggested change. See summary for wording. The SDT agrees and has made the suggested change. See summary for wording.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern agrees with the compliance assessment approach and note to the auditor in the RSAW and recommends that the SDT incorporate these concepts into the standard itself. The RSAW clearly recognizes that events / Emergencies have varying levels of significance. Southern continues to think the current definition of "Emergency" is too broad and is misused in standards development. This standard, and in particular requirements to notify neighboring RCs, should be focused more on issues that can truly impact them, not any situation that could be interpreted as an "Emergency" as it is currently defined. Southern recommends the SDT replace Emergency with Adverse Reliability Impact as it was before. If the SDT does not accept this recommendation, the SDT should consider modifying the requirements or even the definition of "Emergency" to incorporate the concept that an "Emergency" is an operating condition which has not been studied or for which no mitigation plan has previously been developed. For example, having a contingency occur which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance, is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible.

Organization	Yes or No	Question 5 Comments
Response: Emergency is used as it is more inclusive which may lead to more communication. The possession of a mitigation plan does not mean an Emergency doesn't exist. In fact, the mitigation plan is in direct response to an identified Emergency. No change made.		
Northeast Power Coordinating Council Hydro One	No	The Rationale for Requirement R1 explains what review changes were made, and do not address the contents of the Requirements. The Rationale for Requirement R1 should be removed. Measure M1 reflects Part 1.5 not being removed. Why is Part 1.5 being removed? A RC should have the detailed authority. What Requirements does the Rationale on page 7 refer to? The replacement of the word "other" with "adjacent" may leave a reliability gap. Because the words "may impact" already serve as the qualifier for the RC to select who to notify, then the RC is not obligated to notify all RCs hence the scope of notification is finite. We urge the SDT to consider reinserting the word "other" into R1. The Drafting Team should review the use of the phrase "Wide Area" in IRO-008-2 (and other IRO standards) and the phrase "Reliability Coordinator Area" in IRO-014-3. If these phrases are synonymous, then use of one or the other should be decided upon. Regarding the Retention Period, there are no data retention periods for Requirements R3 and R4. Instead, there are retention period requirements for R8 and R9, which do not exist. We urge the SDT and NERC to conduct a thorough and independent quality review for all standards posted for commenting and balloting to avoid unnecessary delays in approving standards due to these errors. Suggest restoring the standard to its original wording.
Response: 1. The SDT agrees and has deleted the rationale box.		

Organization	Yes or No	Question 5 Comments
2. Requirement R1, Part 1.1.5 was deleted as the Reliability Coordinator's authority to act is implied. Measure M1 accurately reflects the requirement language. No change made. 3. Rationale on page 7 refers to Requirement R7 and why the language was added. 4. **"**Other" was replaced by "adjacent" due to overwhelming response by the industry during the first posting. The SDT believes that the wording is correct. No change made. 5. Definition of ***Wide Area*****:** The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits. Definition of ***Reliability Coordinator Area*****:** The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. The SDT maintains these terms are not synonymous. No change made. 6. Data retention for Requirements R3 and R4 has been addressed. See summary for wording.		
Texas Reliability Entity	Yes	Requirements R1 and R2: Texas RE requests the SDT consider whether including Same-Day Operations in the Time Horizon is appropriate. The measures for R1 and R2 are focused on the maintenance of the Operating Procedures, Operating Processes and Operating Plans and not on any specific same-day actions that need to be taken. Texas RE suggests that Same-Day Operations be removed from the Time Horizon for R1 and R2. The Time Horizon of Operations Planning is correct. If the SDT disagrees with the suggested removal of the Same-Day Operations Time Horizon then we request an explanation of why it is appropriate to include it.
Response: The measures simply reflect the language in the requirements and do not apply to any specific time horizon. The SDT believes that Same-day Operations is a valid time horizon for implementing Operating Procedures, Operating Processes, or Operating Plans. No change made.		
Peak Reliability	Yes	The new R4, R5, and R6 should also include "actual or expected Emergency" like R3.

Organization	Yes or No	Question 5 Comments
Response: Since Requirements R4, R5, and R6 follow Requirement R3 in logical and sequential order, the 'actual or expected' language is automatically included by default in the requirements following Requirement R3 and addition of that language would be superfluous. No change made.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 5 Comments
Clark Public Utilities	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 5 Comments
PJM Interconnection	Yes	
CPS Energy	Yes	
MidAmerican Energy Company	Yes	
Response: Thank you for your support.		

6. **The drafting team has proposed a new standard to address outage coordination concerns. Do you agree with the changes made to respond to industry comments to the new standard, IRO-017-1? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes based on industry comments:

R1 Part 1.3. Define the process to evaluate the impact of Transmission and ~~generator~~generation outages within its Wide Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning~~Long-term Planning]*

Organization	Yes or No	Question 6 Comments
City of Austin dba Austin Energy (AE)	No	AE believes R3 and R4 are redundant with requirements in TPL-001-4. TPL-001-4, R8 provides a mechanism for any entity with a reliability need to obtain a copy of the Planning Assessment. Through this requirement, the RC could certainly make a case for receiving copies from the PC and TPs. TPL-001-4, R4 Part 4.1 provides a mechanism for coordination, as necessary. AE notes the SDT's response in comments, "The SDT believes that Requirements R3 and R4 could be incorporated into a future version of TPL-001, but due to timing, is recommending that these requirements should be kept in proposed IRO-017-1 until such a change occurs. The SDT has added revisions to approved TPL-001-4 Requirement R8 to a draft SAR for other possible changes to approved TPL-001-4 which is posted on the project web site as a supporting document." AE suggests these changes should all be considered under the TPL-001-5 SAR and not in a separate IRO-017-1 standard.
Response: The SDT disagrees, and notes that approved TPL-001-4 does not require sharing of Planning Assessments with the impacted Reliability Coordinator. The SDT continues to believe that including this requirement in proposed IRO-017-1 is necessary until a future revision of TPL-001-4. No change made.		

Organization	Yes or No	Question 6 Comments
Georgia Transmission Corporation	No	(1) GTC disagrees that outages are planned for the near term planning horizon (years 1 - 5). Outages are planned and scheduled within the operational planning horizon (up to year 1). The Planning Assessment only covers the near term and the long term planning horizons; it does not cover the operational planning horizon. Furthermore, the RC model can only include the current system that has been built and deals with real time parameters. They cannot grant outages on proposed planning solutions. The Planning Assessment does not provide any useful information for scheduling outages in the operations horizon. An outage request for construction of new stations, lines, or facility upgrades is what is required so that the RC can run a real-time assessment and grant approval for outages. R1 and R2 adequately cover the process to grant outages as they are requested, and sufficiently cover the purpose of this standard. GTC believes R3 and R4 are not necessary for outage coordination in the operations horizon and should be eliminated from this Standard. Additionally, the purpose statement should remove reference to Near-Term Transmission Planning Horizon.
Bonneville Power Administration	No	Regarding R4, Transmission Planning Assessments for the Near Term Planning Horizon do not consider outages that are less than one year in duration. If the transmission system is incapable of serving expected peak load during the Near Term Planning Horizon, current TPL standards and the future TPL-001-4 dictate Corrective Action Plans be undertaken and put in place. As currently written, R4 appears to be duplicative of TPL-001-4. BPA suggests R4 be rewritten to direct TOP and BA coordinate outages conflicts within the Operations Planning Horizon. BPA believes altering R4 in this fashion covers the reliability gap identified by the SW Outage Report, the IERP and FERC with respect to planning of outages. Additionally, this change will logically align R4 with R1.1.2, and R2, directing coordination between RC and TOP/BA.
Response: The SDT disagrees, and notes that some outages are planned over a year in advance. The SDT is intentional about including the Near-Term Transmission Planning Horizon for this reason. The SDT does recommend that proposed IRO-017-1		

Organization	Yes or No	Question 6 Comments
Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Electric Reliability Council of Texas, Inc.	No	1. As an overarching comment, the proposed standard references both transmission and generation outages, but then appears to focus in on transmission outages. As a result, entities responsible for generation outages do not appear to be adequately addressed relative to potential obligations to comply with Reliability Coordinator processes that are developed. This oversight could have significant consequences and the standard should be reviewed to ensure that no gaps exist. At a minimum, those entities responsible for generator outages should be included under the Applicability Section as well as other applicable Requirements (e.g., Requirement R2). More specifically, during the last posting, ERCOT commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While ERCOT agrees that such details can be elaborated in the process document, Part 1.1.2 and other requirements should be expanded to include all appropriate entities to facilitate RC development of a workable and appropriate outage coordination process involving the correct entities. 2. ERCOT is unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners

Organization	Yes or No	Question 6 Comments
		and/or operators. Corresponding changes will need to be made to Requirement R2 as discussed above. ERCOT respectfully notes that Requirement R1 requires some revisions to ensure clarity and ensure that the obligations imposed are clear and unambiguous. Specifically, the requirement indicates that Reliability Coordinators shall develop, implement, and maintain and outage coordination process. However, it does not define what maintenance shall be performed. R1. Each Reliability Coordinator shall develop and implement an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] ERCOT believes “develop” in R1 is unnecessary and only creates confusion when auditing and enforcing. To implement and maintain addresses the reliability concept. Replace R1.5 “document and” with “maintain”, which is sufficient. Document is purely administrative. M1 infers a requirement by including “dated”. By having current specifications for outage analysis during the operations planning horizon should be sufficient in itself for compliance. If a date is required, it should be in the requirement. Additionally, it is noted that use of the term “define” may not adequately connote the level of detail expected regarding the documentation of the outage evaluation and coordination process referenced in sub-requirements R1.3 and R1.4. Accordingly, the following revisions are suggested: 3. ERCOT respectfully notes that Requirement R2 requires some revisions to ensure clarity and ensure that the obligations imposed upon participants in each Reliability Coordinator’s outage coordination process are clear and unambiguous. Accordingly, it is recommended that Requirement R2 be modified as follows: R2. Each Transmission Operator and Balancing Authority shall perform the roles, responsibilities, and activities assigned to its function in its Reliability Coordinator

Organization	Yes or No	Question 6 Comments
		outage coordination process. [Violation Risk Factor: Low Medium] [Time Horizon: Operations Planning] 4. ERCOT respectfully notes that TPL-001-4 already requires distribution of Planning Assessments to various entities. To ensure that all obligations related to Planning Assessments are clearly communicated and consolidated such that they are easily identified and fulfilled, it is recommended that Requirement R3 be deleted from IRO-017 and Requirement R8 within TPL-001-4 be reviewed for the necessary revisions.
Response: The SDT disagrees that Transmission outages are emphasized more than generation outages, and notes that the intention of this standard is to cover both. 1 & 2 - Since the requirement is for the outage coordination process document, the SDT does not consider it necessary to include an exhaustive list of entities, especially in the applicable entities section. Some of the comments appear to be based on the first draft posting of this standard which was subsequently changed. No change made. 3 – The SDT disagrees that a change to this language is necessary. No change made. 4 – The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Northeast Power Coordinating Council Hydro One	No	"Operations Planning" in the Purpose is not defined in the NERC glossary and should not be capitalized. Regarding the Rationale and Time Horizon boxes on page 5: The words in the Rationale is appropriate for a guideline or announcement. It does not belong in a Rationale box.

Organization	Yes or No	Question 6 Comments
		Neither "Time Horizon" nor "Operations Planning Time Horizon" is in the NERC Glossary and should not be capitalized. If those terms are to be considered for inclusion in the NERC Glossary, then they should be included on the Definitions of Terms Used in Standard. The R1 wording "...within its Reliability Coordinator Area" should be removed. Part 1.4 refers to "...other Reliability Coordinators". The box "Note on part 1.5" does not belong in the standard. It is a comment response. "Near-Term Transmission Planning Horizon" is defined as "The transmission planning period that covers Year One through five." The Rationale for Requirement R4 should be revised to just address the "why", and justification for R4. During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, sub-Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support sub-Part 1.1.2 as written, and suggest the Drafting Team to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
Response: The SDT notes that the rationale boxes will be removed after approval and are purely for explanatory purpose during the standard drafting process. No change made.		

Organization	Yes or No	Question 6 Comments
While Time Horizon and Operations Planning Time Horizon are not defined terms in the NERC Glossary, the terms are used in standards in the Time Horizon section that follows every requirement. The rationale box where these terms appear will be removed after final balloting. No change made. R1 – The SDT disagrees and believes that the current language clarifies that the Reliability Coordinator's authority is limited to its Reliability Coordinator Area. However, coordination with neighboring Reliability Coordinators is important, as noted in Requirement R1 Part1.4. No change made. R1.1.2 and R2 – The SDT continues to believe that additional details can be provided in the outage coordination process document. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	In R4, the OC Review Group suggests adding "on the BES" before "with planned outages" to clearly define the BES as the subject portion of the system. Suggested Wording: "R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon."
Response: The SDT believes that this change is unnecessary as standards are written for the BES unless stated otherwise. No change made.		
American Transmission Company, LLC	No	ATC requests the SDT to consider making the following modifications to the proposed Requirements R3 and R4: R3 - To be consistent with the "Long-term Planning" Time Horizon in Requirement R4 and due to Requirement R3's association with the long-term horizon Planning Assessments, ATC suggests that the Time Horizon for Requirement R3 be changed to "Long-term Planning." R4 - To be more consistent with paragraph 90 of the FERC NOPR and because the term "planned outages" has no specific NERC or industry-wide meaning, ATC suggests that the wording of "planned outages" in Requirement R4 be replaced with

Organization	Yes or No	Question 6 Comments
		"scheduled generation, transmission maintenance and transmission construction outages."
Response: R3 – The SDT agrees and has corrected the time horizon. R4 – The SDT believes that the term "planned outages" is sufficiently explanatory. No change made.		
IRC Standards Review Committee Independent Electricity System Operator	No	During the last posting, we commented that the requirement for TOP and BA to coordinate outage plans is inappropriate since the BA does not develop outage plans or schedules; it only receives them from the Generator Owners and may suggest adjustments based on resource/demand/interchange assessments. The SDT's response suggests that these details would be elaborated in the process document and hence no changes were made. While we agree that such details can be elaborated in the process document, Part 1.1.2 should be expanded to include facility owners in order for the RC to develop a workable and appropriate outage coordination process involving the correct entities. We are unable to support Part 1.1.2 as written, and suggest the SDT to either revise it to remove the BA from it, or to expand it to include the facility owners and/or operators. Corresponding changes will need to be made to Requirement R2.
Response: The SDT continues to believe that additional details can be provided in the outage coordination process document. No change made.		
Clark Public Utilities	No	I plan to vote affirmative but wanted to provide a suggestion. R3 is a requirement for the PC and TP to provide its Planning Assessment to the RC. I agree that this should be done, however, it is out of place in IRO-017. It should instead be included in the TPL-001 standard. Even if R3 is retained I encourage a process to eventually move it from IRO-017 to TPL-001.
Response: The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		

Organization	Yes or No	Question 6 Comments
Xcel Energy	No	R3 contains a requirement for the PC/TP to provide a copy of its assessment to the RC. This should be eliminated from this standard and merged into R8 of TPL that already requires the PC/TP to distribute the assessment with other entities. R4 - Planning Assessment performed as per TPL-001-4 is applicable to Long-term Planning time horizon (>12 months) and has no overlap with the Operations Planning time horizon (day-ahead to 12 months). Therefore, it is not clear how Planning Assessment would be an appropriate "tool" to address the outage coordination reliability objective in R4 in the Operations Planning time horizon.
Response: The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		
Dominion Compliance Policy	No	In R2, the Dominion suggests changing the word "function" to "roles and responsibilities" to match R1 Suggested Wording: "R2: Each Transmission Operator and Balancing Authority shall perform the functions roles and responsibilities specified in its Reliability Coordinator outage coordination process."
Response: The SDT does not believe that the suggested change adds clarity. No change made.		
CenterPoint Energy Houston Electric LLC	No	In regards to Requirements R3 and R4, CenterPoint Energy feels the SDT has misinterpreted Paragraph 90 of the NOPR. CenterPoint Energy interprets the language in Paragraph 90 as speaking to the Reliability Coordinator's role in outage coordination in the operational planning horizon. Paragraph 90 mentions generation outages being scheduled 3-5 years in advance and transmission outages being scheduled 1-3 years in advance as part of the planning process. Paragraph 90

Organization	Yes or No	Question 6 Comments
		goes on to mention the need for the Reliability Coordinator, in operational planning, to re-evaluate these planned outages through "... a month-ahead, week-ahead, and sometimes even a day-ahead approval process." CenterPoint Energy does not interpret Paragraph 90 to involve the Reliability Coordinator in the 1-5 year Near Term Planning Horizon process, but to follow its outage coordination process developed in R1.3 and R1.4 to evaluate any previously planned outages within its Wide Area and coordinate resolutions of identified outage conflicts in the Operations Planning Horizon. CenterPoint Energy recommends deletion of Requirements R3 and R4.
MidAmerican Energy Company	No	MidAmerican understands the SDT's intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don't believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. MidAmerican suggests the following language: Each Planning Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
Response: The SDT disagrees, and believes that the Reliability Coordinator may have valuable input into the resolution of potential conflicts. The SDT has revised the rationale for Requirements R3 and R4 to point to the IERP recommendations as well as the FERC NOPR. No change made. However, the SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. The SDT was tasked to address the FERC concern on how the industry is coordinating outages, in part related to pending generation retirements resulting from environmental legislation. One option the SDT considered was to expand the Operation Planning Horizon beyond the seasonal timeframe, which the SDT interprets as covering through Year 1. The SDT instead decided to leverage the existing TPL-001-4 Near-Term Planning Assessment, which occurs during the Near-term Transmission Planning Horizon (year 1 – 5) as opposed to creating an overlap between time horizons and mandating a separate analysis. No change made.		

Organization	Yes or No	Question 6 Comments
PacifiCorp	No	PacifiCorp cannot agree to the proposed new standard without having an understanding of the “Reliability Coordinator outage coordination process”. Additionally, PacifiCorp needs to understand how the Reliability Coordinator will resolve identified outage conflicts. PacifiCorp cannot support the proposed change of the Violation Risk Factor in R3 from Low to Medium.
Response: The SDT believes that processes may differ in different areas, and therefore defers some specifics to the RC’s outage coordination process document. No change made. VRF responses are handled in Q11.		
CPS Energy	No	Propose the following: Strike “Near-Term Transmission Planning Horizon” from Purpose; TPL-001-4 R1.1.1 already requires the model to represent known outages of generation or Transmission Facilities with a duration of at least six months. If outages with a duration of less than six months are required, then this should be a revision to the TPL standard. Strike “4.5. Transmission Planner” from Applicability: All requirements related to the Transmission Planner are either redundant to the TPL-001-4 standard or should be incorporated therein. Strike all of requirement R3: This requirement is redundant to the TPL-001 R8 requirement, since for ERCOT, the Planning Coordinator is the same as the Reliability Coordinator. If it cannot be stricken, then there should be a qualifier that states “this requirement only applies if the Planning Coordinator is NOT the same as the Reliability Coordinator”. Otherwise, the Transmission Planner in the ERCOT system is subject to double-jeopardy regarding this standard and the TPL-001 standard. Strike all of requirement R4: If it is required that the Planning Coordinator, Transmission Planner and Reliability Coordinator all have to work together to jointly develop solutions for planned outages less than 6 months in duration, then this should be reflected in the TPL-001 standard. In general, introducing standards that impose requirements on the Planning Assessment should all be incorporated in the

Organization	Yes or No	Question 6 Comments
		TPL-001 standard as opposed to several disjointed standards, which creates confusion and possible redundant and double-jeopardy situations. Regarding R3 & R4, in general Paragraph 90 perspective is misinterpreted & should be limited to next day (not up to 1-year).
Oncor Electric Delivery LLC	No	Proposed Standard IRO-017-1 R3 states: "Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators." Oncor considers R3 to be a planning requirement that should not be included in IRO-017-1. This Requirement is redundant to approved Standard TPL-001-4 R8 and therefore is misaligned to the Paragraph 81 initiative Criteria B7 to eliminate redundant requirement. Oncor recommends the removal of IRO-017-1 R3.
Response: The SDT does not intend to imply changes to the approved TPL-001-4 outage inclusion criteria. Proposed IRO-017-1 Requirement R4 requires that any identified conflicts be resolved in coordination with the Reliability Coordinator. No change made. The SDT notes that approved TPL-001-4 does not specifically require communication of the Planning Assessment to the Reliability Coordinator, and therefore proposed IRO-017-1 Requirement R3 is not redundant. However, the SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	R2/M2 - Make Reliability Coordinator in Requirement R2 and Measure M2 possessive. The requirement should read '...in its Reliability Coordinator's outage coordination process.' R4 - To focus the coordination effort of the Reliability Coordinator on BES issues we recommend modifying the wording of R4 to state '...for identified issues or conflicts on the BES with planned outages...'
Response: R2/M2 – The SDT agrees with this comment and has update the language as suggested.		

Organization	Yes or No	Question 6 Comments
R4 – The SDT does not believe this change is necessary as all standards are written for the BES unless stated otherwise. No change made.		
Salt River Project	No	Salt River Project (SRP) has a general concern with the R1 requirement for the Reliability Coordinator to develop, implement and maintain an outage coordination process for generation and Transmission outages. Specifically, SRP is concerned if the RC will have the ability to approve or deny outages.
Response: The Reliability Coordinator already has approval authority and responsibility to cancel planned outages in order to address reliability. Proposed IRO-017-1 Requirement R1 requires the Reliability Coordinator to have an outage coordination process that defines roles and responsibilities for outage coordination within its Reliability Coordinator area. No change made.		
South Carolina Electric and Gas	No	In R2, the OC Review Group suggests changing the word “function” to “roles and responsibilities” to match R1. Suggested Wording: “R2: Each Transmission Operator and Balancing Authority shall perform the functions roles and responsibilities specified in its Reliability Coordinator outage coordination process.” In R4, the OC Review Group suggests adding “on the BES” before “with planned outages” to clearly define the BES as the subject portion of the system. Suggested Wording: “R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.”
Response: The SDT does not believe that the suggested change adds clarity. No change made. R4 – The SDT does not believe this change is necessary. No change made.		
New York Independent System Operator (NYISO)	No	See IRC/SRC Comments. The NYISO also would like to suggest the in R1, generation be replaced with generator to be consistent with R1.1.3

Organization	Yes or No	Question 6 Comments
Response: See IRC/SRC response. The SDT agrees that the language should be consistent and has changed Requirement R1 Part 1.1.3 to 'generation'. See summary for wording.		
Puget Sound Energy	No	The effective date for requirements R1 and R2 should be staggered (similar to the drafting team's approach to requirement R1 and R2 of IRO-010-2). It will be very difficult for a BA or TOP to comply with the RC's outage process if that process is finalized on or near the effective date for requirement R2. Requirement R2 is too broad and should be limited to "performing the applicable functions" of the RC's outage coordination process. In addition, what will happen in the case that the RC specifies deadlines or processes that a BA or TOP cannot meet or requirements that are unrelated to outage coordination? To address this issue, in part, the RC should be required to collaborate with the BAs and TOPs in its area during the development of and revisions to the outage coordination process. This may not address all the issues that could arise, but would at least provide BAs and TOPs with time to address shortcomings in their processes prior to incurring a standard violation.
Response: The SDT disagrees that a staggered approach is needed. These items are not going to be created in a vacuum and the SDT believes that the entities involved will be coordinating as the process is developed. No change made. R2 – The SDT does not believe that the suggested change adds clarity. No change made.		
Flathead Electric Cooperative, Inc.	No	This standard seems unnecessary and I do not support it. The obligations are already covered in other standards.
Response: The SDT disagrees and believes that this standard addresses currently existing gaps. The SDT does recommend that proposed IRO-017-1 Requirements R3 and R4 be discussed as part of any future revisions of approved TPL-001-4 but does not have the scope to make such changes at this time. No change made.		

Organization	Yes or No	Question 6 Comments
Lincoln Electric System	No	To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4.R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
NV Energy	No	We understand the SDT's intent to include the RC in Near-Term planned outage solutions and reconciliations; however, we don't believe that the RC has the tools nor the ability to adequately consider outages that may be proposed up to five years from the present day. Any attempts for the TP or PC to jointly develop solutions with the RC for outages in this time frame would be ineffective. We suggest the following language: Each Planning Coordinator and Transmission Planner shall provide notice to its respective Reliability Coordinator regarding identified conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Southern believes that Requirement 4 should provide clear guidance that the Planning Coordinator and Transmission Planner are responsible for initiating the review of solutions with their Reliability Coordinator and additional language should be added to clarify that the joint discussions should only be focused on issues that may impact the Operations Planning Horizon. Southern proposes the following revision to the requirement: "Each Planning Coordinator and Transmission Planner shall coordinate with its respective Reliability Coordinator to jointly develop solutions for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, which may ultimately impact the Operations Planning Horizon."

Organization	Yes or No	Question 6 Comments
MRO NERC Standards Review Forum	Yes	To ensure the distribution of the Planning Assessment is tied to a reliability-related need, recommend modifying Requirement R3 as follows to reflect similar provisions already included in Requirement R4.R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators when issues or conflicts are identified with planned outages in the Near-Term Transmission Planning Horizon.
Response: The SDT does not believe there is harm in requiring that the Planning Assessment be shared with impacted Reliability Coordinators, even if no outage conflicts are identified. No change made.		
Duke Energy	No	While we are open to the suggestions made by the SDT, if the scope of RC is going to be expanded, we believe revisions to the Function Model need to occur first and then distributed to the industry for review and approval. The Functional Model is the foundation for the development of Reliability Standards used by Standard Drafting Teams. As indicated above, these revisions to the Functional Model need to occur first before a substantial change in roles and responsibilities of Functional Entities take place within the standards. R1: No comments R2: Duke Energy suggests the following revision: "Each Transmission Operator and Balancing Authority shall perform the roles and reporting responsibilities specified in its Reliability Coordinator outage coordination process." The use of "roles and reporting responsibilities" in the place of "functions" better aligns with the language used in R1.1 of the proposed standard. R3: No comments R4: Duke Energy suggests the following revision: "Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts on the BES with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon." We believe "identified issues or conflicts on the BES" better aligns with the intent of this

Organization	Yes or No	Question 6 Comments
		requirement and adds clarity that the RC, PC, and TP will jointly develop solutions for conflicts on the BES.
Response: The SDT does not believe that the functional model needs to be revised prior to approving these changes. R2 – The SDT does not believe that the suggested change adds clarity. No change made. R4 – The SDT does not believe this change is necessary. No change made.		
BC Hydro		The requirements as stated can be interpreted as the RC defines coordination processes and activities, and the TOP's and BA's follow. The responsibility for coordination should reside with the TOP's and BA's, in order to manage system and regional impacts of outages. Transmission Operators and Balancing Authorities that already have coordination processes for managing outages within their jurisdictions and with neighbors, would have added requirements, however such practices are already well developed, taking into account standards, mutually agreed requirements and special needs of participants, in addition to system wide needs for communication to support assessments. Under TOP-002-2.1b, R1 and R4, Transmission Operators and Balancing Authorities are already required to coordinate, current-day, next-day and seasonal planning and operations which implies the requirement for outage coordination. While TOP-003-1 R2 and R3 provides more specific and explicit requirements to coordinate outages of voltage regulating equipment and telemetering and control equipment, it does not address the coordination of generation and transmission equipment. While TOP-003 may not (in current form) be comprehensive in its inclusion of equipment types for coordination, TOP-003 however should be the place to identify requirements for coordination of transmission and generation outages. R1 states requirements to convey outage information, but is silent on coordination. However, a revision to TOP-003 standard could place the requirements for determining coordination activities in the TOP's and BA's responsibilities. Nowhere in the IRO-017 is there a requirement for the RC to collaborate with the TOP and BA on defining processes to evaluate impact of outages, or the development of specifications for outage

Organization	Yes or No	Question 6 Comments
		analysis. An RC driven coordination process does not account for differences and needs of TOP's and BA's, that have greater and/or mutual needs for practices not prescribed by RC needs. The requirements provide prescription that only addresses RC needs; involvement of governance (through the RRA involvement), collaboration, and emphasis on continuous improvement of processes would set a better standard, by requiring collaboration in the development of process requirements. The focus of IRO-017 should be on submission of outage information to support RC processes, including timelines for the submission of outages, practices for the communications of outages among the RC, TOP's and BA's responsibility for assessment of system wide conflicts through study assessment, and development of conflict resolution processes to support operations
Response: These requirements were developed in response to IERP recommendations. The SDT believes that processes may differ in different areas, and therefore defers specifics to the Reliability Coordinator's outage coordination process document. The Transmission Operators and Balancing Authorities should participate in the development of the Reliability Coordinator outage coordination process. The SDT sees no conflicts with a Transmission Operator/Balancing Authority process as long as it is coordinated with the Reliability Coordinator process. No change made.		
ACES Standards Collaborators	Yes	(1) We appreciate the drafting team's consideration of previous comments and subsequent revisions.
Seattle City Light	Yes	
Florida Municipal Power Agency	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 6 Comments
Peak Reliability	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Hydro-Quebec TransEnergie	Yes	
Texas Reliability Entity	Yes	
City of Tallahassee, TAL	Yes	
Consumers Energy Company	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
Ameren	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

Organization	Yes or No	Question 6 Comments
Northeast Utilities	Yes	
PJM Interconnection	Yes	

Response: Thank you for your support.

7. **Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT deleted 'Operations Planning' from all time horizons concerning Operating Instructions as Operating Instructions are issued in Real-time environments.

The SDT has made the following changes due to industry comments:

R1. Each Transmission Operator shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its ~~e~~Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known ~~other~~ impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of sustained outages of telemetering ~~equipment,~~and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of ~~planned~~ sustained outages of telemetering ~~equipment,~~and control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall monitor the following as necessary for determining SOL exceedances in its Transmission Operator Area:

10.1 Within its Transmission Operator Area:

10.1.1 Facilities,

10.1.2 ~~t~~The status of Special Protection Systems, and

10.1.3 ~~sub-100 kV facilities~~Non-BES facilities identified as necessary by the Transmission Operator ~~, within its Transmission Operator Area~~

and

10.2 Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

10.2.1 Facilities,

10.2.2 Status of Special Protection Systems, and

10.2.3 Non-BES facilities.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, ~~to ensure~~in order for ~~that~~ it ~~is~~to be able to perform its reliability functions.

R15. Each Transmission Operator shall inform its Reliability Coordinator of ~~its~~ actions taken to return the system to within limits when a SOL has been exceeded.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and ~~Real-time Assessment~~analysis capabilities.

R18. Each Transmission Operator ~~and Balancing Authority~~ shall ~~always~~ operate to the most limiting parameter in instances where there is a difference in SOLs.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area~~(Balancing Authority Area)~~.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its ~~Transmission Operator Area (~~Balancing Authority Area~~)~~.

The SDT has made the following non-substantive changes to other standards for consistency:

TOP-003-3 Requirement R1 Part 1.1: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data as deemed necessary by the Transmission Operator.

IRO-001-4 Requirement R1: Each Reliability Coordinator shall act~~, or direct others to act, by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

IRO-002-4 Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

IRO-010-2 Requirement R1 Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Organization	Yes or No	Question 7 Comments
City of Austin	No	City of Austin dba Austin Energy (AE) supports the streamlining effort and removal of redundant requirements. However, AE offers the following comments: (1) AE continues to disagree with the change to R1, which removes the "responsibility and clear decision-making authority" language from the previous standard. AE believes the authority language provides clarity and substance in an easily recognizable format. AE believes the remaining requirements in the TOP/IRO families instruct the TOP to "act, or direct others … to act" while providing more specificity regarding such actions. In this way, R1, as proposed, is redundant and difficult to demonstrate from a compliance perspective given its general nature. (2) AE understands the SDT's intent in including the Operations Planning time horizon with respect to Operating Instructions is to cover the concept of "next day directives" previously in IRO-004-2. However, IRO-004-2, as written is limited to RC directives. AE suggests the SDT remove the Operations Planning Horizon from R1. (3) R9 is too broad a scope to be useful. The phrase "…outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels…" is all encompassing. If each BA or TOP were to contact the RC every time there was the slightest glitch with telemetering or every time an ICCP link or microwave channel was cycled for maintenance or some type of momentary signal fade, the RC's phone would be ringing continually. The intent of

Organization	Yes or No	Question 7 Comments
		this requirement is to be sure all entities are aware of a loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 is sufficient to meet the intent. See suggested wording below: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. (4) R19 and R20 are redundant with existing COM standards. They will remain redundant when future COM standards come into effect. AE requests the SDT remove these added requirements from TOP-001-3.
Response: (1) The SDT disagrees that such a requirement is still needed in today's environment. However, the SDT has revised the wording of Requirements R1 and R2 to provide clarity. See summary for wording. (2) The SDT has removed Operations Planning from the time horizon of all requirements dealing with Operating Instructions as those instructions are Real-time oriented. (3) The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made. (4) The SDT does not agree that Requirements R19 and R20 are redundant with anything in the proposed COM standards. No change made.		
South Carolina Electric and Gas	No	With regard to R13, we understand and support the need to do real-time assessments at least once every 30 minutes to avoid being in an unstudied state. However, if significant SCADA losses occur or an ICCP link is lost to a neighboring BA/TOP, the State Estimator solution can be affected to such a degree that a real-time assessment, with real-time data, may not be possible within 30 minutes. While this does not happen often, it does occur on occasion, but the requirement allows for NO exceptions to the 30 minute requirement. (As an example. the MOD-001 standard

Organization	Yes or No	Question 7 Comments
		allows for a certain number of hours that ATC may not be recalculated without being in non-compliance).
Response: The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. For the specific example cited in the comment, the SDT believes that entities have several different methods for resolving the situation. One (and the preferred method) is to notify whomever is cited as providing capabilities pursuant to approved EOP-008-1 and let that entity take over the analysis. Another possible route to take would be to have the operator do an assessment of the system. This could involve the operator studying the Real-time data, the alarm subsystem, system topology, etc., to see if anything has changed since the last assessment. The operator could also call out to other Transmission Operators and the Reliability Coordinator to see if they have noticed anything through scans or analysis that should be taken into account. Once the operator has done this, he/she could provide an assessment of the situation using their professional judgment and chart a course of action as necessary or simply 'certify' that everything is status quo from the last Real-time Assessment. The operator should then communicate the findings as appropriate while recording this information, as well as an indication as to how the assessment was made, in the Operator Log. While the SDT believes this approach is less than optimal, and can't be sustained for a long period, as long as the system hasn't significantly changed, it should be acceptable for a period to cover a short-term 'glitch'. No change made.		
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated. R9 states:"R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." To be consistent with IRO-008-2 R4, where

Organization	Yes or No	Question 7 Comments
		'NERC registered' has been struck (also struck in TOP-002-4), Dominion suggests 'NERC registered' also be struck in R9 in TOP-001-3.
Response: The SDT has replaced the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording. The SDT has eliminated 'NERC registered' from the requirement for consistency. See summary for wording.		
ACES Standards Collaborators	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 should be revised by removing the words "direct others to act" and stating that the TOP shall issue Operating Instructions to ensure reliability of its TOP Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the TOP shall act or direct others to act by issuing an Operating Instruction, the TOP is limited to only this option. We recommend alternative language for this requirement, "Each TOP shall act or issue Operating Instructions to ensure reliability of its TOP Area."

Organization	Yes or No	Question 7 Comments
		(3) Requirement R1's language of requiring the RC to "ensure reliability" could be used as a zero defect standard if there is an event. "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." Requirement R2 should be revised by removing the words "direct others to act" and stating that the BA shall issue Operating Instructions to ensure reliability of its BA Area. The actions taken by an RC to direct others to act is inherent in the definition of Operating Instruction and is redundant with the language in the requirement. This additional clause is wordy and may not fully capture what the drafting team is trying to achieve. By stating that the BA shall act or direct others to act by issuing an Operating Instruction, the BA is limited to only this option. We recommend alternative language for this requirement, "Each BA shall act or issue Operating Instructions to ensure reliability of its BA Area." (4) Requirement R2's language of requiring the RC to "ensure reliability" could be used as a zero defect standard if there is an event. "Each RC shall act or issue Operating Instructions in accordance with its responsibilities as a RC of its RC Area." (5) Requirements R3, R4, R5 and R6 should be revised to remove the LSE function. (6) For Requirements R10 and R11, we recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (7) Requirement R10 is also problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term "Facilities."

Organization	Yes or No	Question 7 Comments
		(8) We appreciate the clarification that Requirement R13 is not intended to require a Transmission Operator to have state estimation and real-time contingency analysis. We recommend revising the RSAW to ensure that auditors will review events to avoid this standard being zero defect. (9) We appreciate the clarification for Requirement R18 that derived limits are SOLs and have removed the GOP from this requirement. (10) Requirements R19 and R20 have a parenthetical (Balancing Authority Area) that should be removed to avoid confusion. If both TOP Area and BA Area are intended, please list both without parentheses.

Response: 1. As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made.

2. The SDT agrees and has revised the wording of the requirement. A corresponding change was made to Requirement R2 for consistency. See summary for wording.

3 & 4. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.

5. See response to item 1.

6. As previously stated, if the change in term is approved, there will be a project to go through all of the applicable standards to make the needed correction. No change made.

7. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording.

8. The SDT recognizes your comment and will forward the comment to the responsible party.

Organization	Yes or No	Question 7 Comments
9. Thank you for your support. 10. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Georgia Transmission Corporation	No	(1) The current proposal for R3 and R5 as written could overly expose the DP and LSE excess compliance obligations for routine switching operations performed on a daily basis which are not performed to “ensure the reliability” of the BES, such as scheduled outages for maintenance items and new construction, etc. The DP and LSE implement Operating Instructions on non-BES equipment on a routine basis, but the implementation of Operating Instructions on BES or non-BES equipment “to ensure the reliability of the BES” is not very routine. Based on the stated purpose of the standard, GTC believes this requirement for the DP/LSE should complement COM-002-4 R6 relating to Operating Instructions during an Emergency “affecting the reliability of the BES”. We believe that the use of the NERC term “Emergency” would properly capture the stated intent of this standard. GTC proposes the language “[during an Emergency]” be added after “....shall comply with each Operating Instruction issued by its Transmission Operator(s) [during an Emergency] “. Based on the stated purpose (which we believe is adequately captured by the use of the term “Emergency”), at a minimum, Operating Instructions issued to ensure the reliability of the BES should be the only Operating Instructions covered by this standard (as was done in R1 and R2). As is currently written Operating Instructions for scheduled outages associated with maintenance items and new construction will also be in scope which conflicts with the stated purpose of this standard. (2) Based on the functional model, the TOP is responsible for the Real-time operating reliability of its Area and has the authority to ensure that its TOP Area operates reliably. Thus, it is clear to us that part of the job of the TOP and/or BA to ensure that the Operating Instructions they issue are performed. Recipient entities such as the DP would rely on the TOP or BAs voice recordings as evidence which is duplicative to what the TOP or BA is already collecting. We would suggest the following:R3: Each Transmission Operator is to verify each Operating Instruction it issues as a part of R1 is completed, unless informed that such action cannot be physically implemented or

Organization	Yes or No	Question 7 Comments
		it would violate safety, equipment, regulatory, or statutory requirements. R4: Each Balancing Authority is to verify each Operating Instruction it issues as a part of R2 is completed, unless informed that such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. An additional benefit to writing the requirements in this manner is a substantial reduction in redundant administrative record-keeping. TOPs and BAs will already be collecting such information as a part of R1 and R2, so requirements along the lines of those proposed above would provide the additional benefit of preventing duplication of records between multiple entities, keeping records of these Operating Instructions performed with the TOP and BA.
Response: (1) The purpose of the standard is to prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences. It is not practical for Transmission Operators to direct switching on the distribution system to prevent such occurrences. However, Transmission Operators would direct Distribution Providers and Load-Serving Entities to perform functions identified in the Functional Model, such as Load shed or voltage reduction to prevent or mitigate such occurrences. The SDT does not believe that the present wording of the requirement places any entity in undue jeopardy or strays from the stated purpose of the standard. The SDT does not believe that constraining the requirement to only be applicable during Emergencies is a viable alternative. Non-Emergency situations can lead to Emergencies and the purpose of issuing an Operating Instruction during those non-Emergency situations is to avoid potential Emergencies down the road. No change made. (2) The SDT does not agree that the responsibility for monitoring these activities should be the sole responsibility of the Transmission Operator or Balancing Authority. Consistent with responsibilities defined in the Functional Model, Distribution Providers and Load-Serving Entities would also need to maintain evidence of such mitigation action as Load shed or voltage reduction. No change made.		
Texas Reliability Entity	No	1) Requirement R8: Texas RE disagrees with the addition of the word “known” to impacted TOPs and BAs. Within the interconnected system, a TOP may not always know who is impacted. It would be prudent to also notify TOPs who may be impacted. We suggest the SDT keep the original language “impacted Transmission Operators.” Requirement R9 did not add “known” to the phrase “impacted interconnected NERC registered entities” which is inconsistent with R8. Texas RE

Organization	Yes or No	Question 7 Comments
		recommends that R8 and R9 should be consistent when the SDT determines if "known" should be included or not. 2) Requirement R9, M9 and R9 VSL: Suggest the SDT remove "NERC registered" to be consistent with other standards in this project. 3) Requirements R9 and M9: The two paragraphs need to be consistent and cover both planned and unplanned outages. Texas RE recommends changing the two paragraphs so that "outages" is preceded by "planned and unplanned." 4) Requirement R10: The use of the term "within its Transmission Operator Area" in R10 may lead to potential conflicts and reliability gaps, specifically for monitoring of SPS's. For example, an SPS owned by a GO/GOP would not have to be monitored by a TOP since it is not within its Transmission Operator Area (i.e. the generator is not a "Transmission" asset per the definition), even though the operation or misoperation of the SPS may lead to SOL violations within the TOP area. Texas RE suggests clarifying language be added by the SDT to assure that a TOP monitors all facilities and Special Protection Systems within its area; not just those that fall under the definition of transmission asset. 5) Requirement R10: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality. The SDT may also consider modifying the language to state "identified as necessary by the Transmission Operator or Reliability Coordinator." 6) Requirements R13, R14, R15: Texas RE requests the SDT consider whether there should be a similar requirement for a BA to perform a Real-time Assessment. The following questions are submitted to assist the SDT's assessment of our request. In

Organization	Yes or No	Question 7 Comments
		real-time, how will a BA control frequency or know if it is experiencing or about to experience a capacity emergency unless it is performing such an assessment? For R14, how does the BA initiate its Operating Plan for an EEA unless it sees a capacity deficiency through a Real-time Assessment? For R15, how does the BA notify the RC of a capacity emergency unless it sees a capacity deficiency through a Real-time Assessment? 7) Requirement R19: The term "(Balancing Authority Area)" appears to be a typo and should be removed. 8) Requirement R20: The term "Transmission Operator Area (Balancing Authority Area)" appears to be a typo and should be replaced with "Balancing Authority Area."

Response: 1) The SDT added the term 'known' based on industry feedback for the exact reasons Texas Reliability Entity is requesting the term to be removed. The addition of the term 'known' reinforces that the Transmission Operator only needs to notify Transmission Operators/Balancing Authorities that are recognized as being impacted through the analysis functions it is performing. However, the SDT has removed 'other' for consistency and clarity.

2) VSL comments are handled in q11.

3) The SDT agrees and has revised the wording to eliminate 'planned' from the Measure which means that both planned and unplanned outages are included. See summary for wording.

4) The SDT believes that the Special Protection System cited would be considered a transmission asset regardless of ownership and would be monitored by the Transmission Operator as part of this requirement. However, the SDT has modified Requirement R10 based on industry feedback for clarity. See summary for wording.

5) Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. See summary for wording.

6) The SDT does not believe that the Balancing Authority can perform a Real-time Assessment given the proposed definition. Nor does the SDT believe that the Balancing Authority needs to perform a special assessment in order to fulfill its responsibilities. There

Organization	Yes or No	Question 7 Comments
are mechanisms already in place in the BAL standards that allow the Balancing Authority to monitor and react to the proposed situations. In addition, the Reliability Coordinator and Transmission Operator would be monitoring the system and coordinating with the Balancing Authority as needed. No change made. 7) & 8) The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Independent Electricity System Operator	No	a. During the last posting, we expressed a concern over the ambiguity in R9 as the phrase "between the affected entities" can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, we suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities b. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
Response: a. The SDT does not agree with the commenter's interpretation of the requirement wording and believes that it is clearly stated that the communication is only between the affected entities. No change made. b. The SDT has already made NERC management aware of the need for a future project to separate the Transmission Operator and Balancing Authority requirements into separate standards.		

Organization	Yes or No	Question 7 Comments
Associated Electric Cooperative, Inc. - JRO00088	No	R1 and R2: The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI. Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: "Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area." AECI agrees with SPP comments regarding R10:R10 - We have concerns with the existing language in Requirement R10 which when applied in the real-world of today's audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn't model enough of the neighboring TOP's Area? Isn't this really the function of the RC and aren't we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: Each Transmission Operator shall monitor the following to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.10.1 Facilities within its TOP Area 10.2 Status of Special Protection Systems identified as applicable by the Transmission Operator 10.3 Sub-100 kV facilities identified as

Organization	Yes or No	Question 7 Comments
		applicable by the Transmission Operator, and 10.4 Facilities within neighboring Transmission Operator Areas identified as applicable by the Transmission Operator
Response: The SDT agrees and has made the suggested changes. See summary for wording. The SDT has modified the language of Requirement R10 for clarity. See summary for wording.		
Flathead Electric Cooperative, Inc.	No	Again, DPs should not have evidence requirements when the BA/TOP is recording the other end of the line. Suggest deleting "Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format." from any DP measure.
Response: The SDT does not agree that the responsibility for monitoring these activities should be the sole responsibility of the Transmission Operator or Balancing Authority. Consistent with responsibilities defined in the Functional Mode, DP and LSE would also need to maintain evidence of such mitigation action as load shed or voltage reduction. No change made.		
American Transmission Company, LLC	No	ATC requests the SDT to consider making the following changes to the proposed Requirement R10 based on the corresponding technical rationale. It is ATC's understanding that the intention of the SDT is to not require each Transmission Operator to monitor all Facilities and all Special Protection Systems in the neighboring TOP areas. However, the structure of the sentence in Requirement R10 does not provide this clarity. Rather, the sentence requires each TOP to monitor all Facilities, all Special Protection Systems and a subset of sub-100kV facilities for its TOP area and its neighboring TOP areas. If the TOP is to be given discretion on which neighboring Facilities and Special Protection Systems are to be monitored, then ATC suggests that Requirement R10 be modified as:"R10. Each Transmission Operator shall determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area by monitoring: R10.1 Within its Transmission Operator Area: R10.1.1 Facilities R10.1.2 Status of all Special Protection Systems R10.1.3 Sub-100 kV facilities identified as necessary by the Transmission Operator R10.2 Within neighboring Transmission Operator Areas and

Organization	Yes or No	Question 7 Comments
		identified as necessary by the Transmission Operator: R10.2.1 Facilities R10.2.2 Status of Special Protection Systems R10.2.2 Sub-100kV facilities” Please Note: ATC also requested via the RSAW Feedback Form to modify the RSAW’s evidence listing for proposed Standard TOP-001-3 to address inconsistencies with the language of Requirement R10 or any modifications to this language based on ATC’s comments. For example, if the R10 language is left unchanged, the Facilities evidence should be “all Facilities within its TOP area and those Facilities in neighboring TOP areas determined necessary by the TOP.” This structure would also be applied to Special Protection Systems. For sub-100kV facilities, the evidence should be “those sub-100kV facilities determined necessary by the TOP” without a need to reference its TOP area or neighboring TOP areas since that is the plain reading of the requirement.
Response: The SDT has re-structured the requirement for greater clarity. See summary for wording.		
BC Hydro	No	BC Hydro’s concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of “Operating Instructions” broadens to non-emergency situations. Requirement R3 and R4 have the BA’s complying with TOP’s Operating Instructions. BC Hydro’s concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no “out” clause based on reliability conflicts - such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an “out” clause.
Response: If an entity wishes to set up an additional higher level of communications, as is apparently intended through the use of Reliability Directive, that entity is free to do so as long as it properly documents the process and continues to follow the COM-002-4		

Organization	Yes or No	Question 7 Comments
established protocols. As far as the definition of Reliability Directive is concerned, the SDT believes that the FERC NOPR clearly stated that the approach proposed in previous projects was not acceptable. Furthermore, the SDT's decision to utilize the term Operating Instruction was in part due to the concept that a directive is inclusive within its definition. The SDT believes the use of Operating Instruction(s) allows Reliability Coordinators and Transmission Operators to address or prevent situations that could lead to an Emergency. The Reliability Directive definition was never approved by FERC (see NOPR) and will eventually be withdrawn. The use of Operation Instruction is consistent with proposed COM-002-4. No change made. The SDT believes that entities already have established processes for conflict resolution and that the Reliability Coordinator can always be called upon to adjudicate if needed. No change made.		
Bonneville Power Administration	No	BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, "... operations that result in, or could result in, an Emergency." It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard conflates events that are actually happening with events that may happen at some point. BPA suggests the drafting team clearly separate these two concepts. Specifically, R8 requires entities to identify "... operations that result in, or could result in, an Emergency," without any qualification for likelihood. BPA does not feel it is appropriate to treat an actual Emergency the same way it treats a possible future Emergency that could, but likely will not happen.
Response: The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		

Organization	Yes or No	Question 7 Comments
The SDT believes that the standards need to be taken as a whole and that Requirement R8 refers to Real-time Assessments as well as Operational Planning Analysis results both of which can point to potential problems. Examples of emergent conditions that could result in an Emergency are notification of “stuck breaker”, pending equipment failure or de-rates, or notification of relay degradation. No change made. The SDT believes that likelihood of occurrence is not an issue here. Transmission Operators should make the notifications so that others are informed of the possibility and can take appropriate actions as dictated by internal policies. The SOL White Paper further defines acceptable BES performance and mitigating strategies to control pre-contingency and post-contingency SOL exceedances. No change made.		
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy feels Requirement R1 is general and may provide double jeopardy with other requirements that dictate specifics on when and under what circumstances TOPs are required to act and direct others to act. CenterPoint Energy suggests reverting back to authoritative language requiring TOPs giving its Operating Personnel the authority to act, or direct others to act: “Each Transmission Operator shall provide its Operating Personnel with the authority to act, or direct others to act...” Another suggestion is to delete the Requirement completely due to its broad generality which is already included in the Functional Model, while keeping R3 and R4 for accountability of any Operating Instructions from the Transmission Operator to be followed. CenterPoint Energy also feels the language in R1, “...to ensure the reliability of its Transmission Operator Area” puts an unavoidable burden on the TOP for when an unexpected event occurs. CenterPoint Energy suggests changing ‘ensure’ to ‘maintain’. These comments would also apply to IRO-001-4, R1. R10. CenterPoint Energy feels monitoring Facilities reaching into a neighboring Transmission Operator Area needs more direction. The term ‘as necessary’ is too vague for a TOP to determine how far into a neighboring Area or what specific equipment contained in another TOP Area it would need to monitor to determine SOL exceedances.

Organization	Yes or No	Question 7 Comments
		CenterPoint Energy also feels it is the RC function to monitor and determine any reliability issues which may overlap or cascade between TOP Areas as they have the Wide Area view. CenterPoint Energy recommends removing 'neighboring areas' from R10.
Response: The SDT does not believe there are other requirements in the standards that would produce a double jeopardy situation with Requirement R1. The SDT also believes that Requirements R1 and R3 (as well as Requirements R2 and R4) are a logical and consistent presentation of the use and need for Operating Instructions. The SDT did modify Requirements R1 and R2 based on industry feedback. See summary for wording. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Corresponding changes were made to proposed IRO-001-4. See summary for wording. The SDT believes that the Transmission Operator is in the best position to judge what is necessary and that credit needs to be given to the Transmission Operator's professional judgment in this area. No change made. Monitoring of neighboring facilities does not mean that the Transmission Operator is now taking control of overlap issues from the Reliability Coordinator. The SDT believes that the Transmission Operator's models require information from neighboring systems in order for Operational Planning Analysis and Real-time Assessments to solve accurately. Specifically, a Transmission Operator needs to monitor the status and flows of neighboring Facilities that if outaged could adversely impact its Transmission Operator Area. The SDT has re-structured the requirement for greater clarity. See summary for wording.		
HHWP	No	Draft 2 has not satisfactorily addressed the circumstances of small transmission operators. Most small TOPS operate very simple and predictable systems, with the capacity for only minimal impacts on the BES. Draft Requirement TOP-001-3, R13 which will require such TOPs to perform, review and document real-time assessments every 30 minutes, unnecessarily burdens such TOPs with additional process, expense and resource requirements that will contribute no added reliability above and beyond the real-time assessment processes which Reliability Coordinators already have in place

Organization	Yes or No	Question 7 Comments
Response: The requirement allows for an entity to arrange for another entity to perform the assessment which would alleviate any resource burdens on smaller entities. The SDT believes that the Real-time Assessment for small Transmission Operators with simple and predictable systems would be minimal under normal operating conditions. No change made.		
Ingleside Cogeneration , LP	No	ICLP believes that the project team has completely bypassed the language and intent of COM-002-4 by creating zero-tolerance requirements in TOP-001-3 R3 through R6. In R3-R6, every Operating Instruction, no matter how routine, must be perfectly executed and documented to the liking of an audit team. By comparison, COM-002-4 focuses only on training and ongoing reinforcement on the proper communications protocol to be used in the transaction of Operating Instructions. We understand that BES reliability depends far more heavily on TOP-001-3's requirements to execute an Operating Instruction - and not so much COM-002-4's oversight of the protocols to use. However, an Operating Instruction can be any communication to "change or preserve the state, status, output, or input" of a BES element/facility, which covers significant ground. If a single log entry is vague or missing, a severe penalty awaits even the most conscientious GOP. This means that the solution lies in the compliance approach to TOP-001-3, which should vary by the priority of the communication. For example, ICLP believes that every Operating Instruction issued during a declared Emergency, or one prefaced with "this is a mandatory Operating Instruction" should be properly documented by the recipient in a zero-tolerance manner. This would include time-stamps of conversations; an acknowledgement that three-part communications were used; and a coherent recount of the steps requested, taken, and their results. All other Operating Instructions would only be examined by an auditor if shown that slow or improper execution put the BES at risk. This is not a substantial hurdle to overcome - particularly since the issuer and recipient will both have telemetry and/or written records of an incidence of concern. The CEA could then dig deeper to determine if a pattern of poor performance by the GOP exists; which is really the behavior that we all want to eliminate over the longer term.

Organization	Yes or No	Question 7 Comments
Indiana Municipal Power Agency	No	IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow. What happen to results-based standards? Just keeping the telephone logs in many instances will not be enough and it will require much more documented evidence to show that an entity followed the TOP's Operating Instructions. If a Generator Operator is asked to change MW/VAR output or asked to maintain the same output numerous times in a day by its Transmission Operator, it will have to keep evidence to show that it carried out every single Operating Instruction throughout the entire day. Does this mean keeping track of the output of the Generator for the day and giving the entire log to the auditor to show the Generator Operator carried out each Operating Instruction?
Response: The SDT believes that complying with Operating Instructions is extremely important for the reliability of the system and that emphasis in audits will be on whether the Operating Instruction was followed as opposed to a missing log entry. The SDT suggests that the commenter's points would be better submitted in the RSAW process for proposed TOP-001-3. The current RSAWs instruct the auditor to focus on EOP-004 reportable events. No change made.		
Hydro-Quebec TransEnergie	No	In R4, modify the second "its Transmission Operator" by "that Transmission Operator" for consistency with the wording of R6. Also modify corresponding element in the Table of Compliance Elements. In R9 and M9, remove the expression "interconnected NERC registered" for consistency with IERP recommendation regarding TOP-002-4 R3 In R17, replace "analysis" by "Real-time Assessment" for consistency with R16. R18 is unclear. What does "where there is a difference in SOLs" mean? Difference in SOLs compared to which SOL? A "difference" implies a comparison between two SOLs. That portion of the requirement should be clarified. The rationale for R19 and R20, which are related to data exchange capabilities, states that they're added for consistency with IRO-002-4 R2 whereas R2 addresses RC's System Operator authority.

Organization	Yes or No	Question 7 Comments
		In R19 and R20 why the use of "Transmission Operator Area (Balancing Authority Area)" for both requirements? R19 should say "Transmission Operator Area" and R20 should say "Balancing Authority Area" for consistency with associated Measures. Compliance section 1.2: As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements: VSLs for R8 and R9 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. Example: "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted Transmission Operators or other known impacted Balancing Authorities that the Responsible Entity did not inform of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas or Balancing Authority Areas when conditions did permit such communications :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" The whole wording of the requirement could be omitted for more clarity :"Violation Severity Levels for requirement 8 are determined based on the number of other known impacted entities that the Responsible Entity did not inform in accordance with that requirement :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.

Organization	Yes or No	Question 7 Comments
Response: The SDT does not believe that the suggested change adds any clarity. No change made. The SDT agrees and has made the suggested change. See summary for wording. The Balancing Authority does not perform Real-time Assessments per the proposed definition but does perform other analyses that are defined in the BAL standards. Therefore, the SDT believes that the current wording is correct. No change made. The requirement applies to the instance where differing Transmission Operators, for some unknown reason, are working off of different SOLs for the same equipment. The SDT believes that the wording is clear and has been understood by the industry. However, the SDT has deleted the Balancing Authority from the requirement. See summary for wording. The rationale box contained a typo which has been fixed. The correct reference is proposed IRO-001-4 Requirement R1. The SDT has corrected the typo in requirements R19 and R20. See summary for wording. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. VSL comments are handled in Q11. How the SOL Exceedance White Paper will be included is to be determined by NERC staff. It may be a hyperlink or it may be the inclusion of the entire paper.		
Xcel Energy	No	In R7, how is the entity receiving the request able to know if the requesting entity has indeed implemented its emergency procedures? Suggest removing that qualifier, or change the requirement to state that “Each Transmission Operator shall assist Transmission Operators experiencing an Emergency, if requested, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.” R10 is not written clearly. Suggest restructuring. Each Transmission Operator shall monitor: o Facilities (including sub-100 kV facilities needed to maintain reliability) within its Transmission Operator Area and o Facilities (including sub-100 kV facilities needed to maintain reliability) in neighboring Transmission Operator Areas to

Organization	Yes or No	Question 7 Comments
		maintain reliability within its Transmission Operator Area o Status of Special Protection Systems within its Transmission Operator Area R16 & R17 should state "...approve or defer/deny..." Is R18 only for derived limits or if there is a difference in any limit? Or is the intent of the requirement to be " ... when limits are derived and there are differences when comparing solutions."?
Response: The SDT believes that the requested Transmission Operator will ascertain whether the requesting entity has implemented its procedures. No change made. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace 'sub-100 kV' with the term 'non-BES facilities' to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. See summary for wording. The SDT believes that absence of approval by the operator is equivalent to deny and that the additional wording is not necessary. No change made. The language on derived limits was removed in the second posting. The Transmission Operator shall operate to the most limiting SOL at any point in time.		
Consumers Energy Company	No	In Requirement 1 and 2 the term reliability provides a vague stipulation. "... by issuing Operating Instructions to ensure the reliability of its Transmission Operating Area." I don't know if language can be suggested at this point, but I would prefer to see "stability" rather than "reliability".
Response: The SDT believes that 'reliability' is the appropriate term. No change made.		
Puget Sound Energy	No	It is nearly impossible for entities to comply with requirements R1 and R2 of TOP-001-3 as currently drafted. This issue is highlighted (not corrected) by the draft RSAW's approach of evaluating compliance only during events. RSAWs are only guidance -

Organization	Yes or No	Question 7 Comments
		reading footnote 1 of the current RSAW template makes it clear that the RSAW is a reference document only and entities cannot depend on the approach outlined there to resolve ambiguities associated with a requirement. The place to resolve ambiguities is in the standard's language, not in the RSAW. An entity must comply with any requirement at all times; it does not matter if the enforcement authority only checks compliance during certain periods. If an entity fails to comply with the requirement at any other time, that entity is obligated to self-report the violation. In this situation, then, each entity must "ensure" the reliability of its area 24/7/365 to be compliant with requirement R1 or R2. This means that any reliability event could reflect an entity's failure to comply with R1 or R2 because the entity failed to ensure the reliability of its area during that event. But can any entity really ensure the reliability of its area? This just doesn't seem possible because there are so many factors outside of an entity's control that can affect the reliability - for example, equipment failure or a fire along transmission lines. In addition, the burden of monitoring compliance based on the proposed language is immense. Requirements R1 and R2 of the currently effective TOP-001-1a require entities to take action to "alleviate operating emergencies". This is a high bar, but not so high that an entity cannot comply when factors beyond its control affect the reliability of its area. In addition, using this language in the proposed standard would be consistent with the RSAW's approach and ease the associated compliance monitoring obligation, while still requiring an entity to act to protect the reliability of its area.
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified

Organization	Yes or No	Question 7 Comments
		phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc). Phase angle inputs (from PMU's etc) or phase angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. With regard to R13, MidAmerican believes the SDT has improved the language by revisions such that the TOP shall "ensure that a Real-time Assessment is performed at least once every 30 minutes;" however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, MidAmerican suggest the following: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP."
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be		

Organization	Yes or No	Question 7 Comments
supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
Northern Indiana Public Service Company (NIPSCO)	No	NIPSCO feels R10 should align with the Operational Planning Analysis Requirement and include a reason such as "to determine SOL exceedances". NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
Response: Requirement R10 includes the term 'to determine any SOL exceedances". No change made. The SDT does not agree. Proposed COM-001-2 is for interpersonal communications which covers voice communications. The purpose of proposed TOP-003-3 focuses on defining data requirements. The SDT added Requirements R19 and R20 to cover real-time data exchange. No change made. The SDT does not agree. Requirements R16 and R17 are about the Real-time data exchange and analysis capabilities that an operator has at his/her disposal and not about Transmission and generation outages as described in proposed IRO-017-1. No change made.		
PacifiCorp	No	PacifiCorp needs clarification concerning how R16 works in tandem with the Reliability Coordinator outage process noted in IRO-017-1. Additionally, PacifiCorp questions whether we have the ability to compel a non-NERC Registered Entity to provide data in order to maintain reliability in the Transmission Operator Area.

Organization	Yes or No	Question 7 Comments
		Also, inclusion of the Near-term Planning Horizon (which is 1 - 5 years) into the future isn't appropriate. This should be addressed in a revised TPL standard. Does this mean that Planning must coordinate all proposed 6 month (see TPL-001-4 R1 effective on 1/1/2015) or longer outages with the DMCC up to 5 years into the future every X days, months, or annually?
Response: Requirement R16 is about the Real-time data exchange and analysis capabilities that an operator has at his/her disposal and not about Transmission and generation outages as described in proposed IRO-017-1. Standards only apply to NERC registered entities, specifically those entities identified in the applicability section of each standard. PacifiCorp would need to rely on Interconnection or Operating Agreements for authority outside of the NERC Standards. The SDT can only write standards that apply to NERC Registered Entities. The SDT assumes this comment is about proposed IRO-017-1 and not about proposed TOP-001-3 which does not pertain to planning. The inclusion of the Near-Term Transmission Planning Horizon in proposed IRO-017-1 is a direct response to the FERC NOPR and IERP report. As is pointed out in the rationale box for proposed IRO-017-1 Requirement R4, and shown in the second posting inclusion of a draft SAR for future revisions to approved TPL-001-4, the long-term goal is to move appropriate requirements from proposed IRO-017-1 to a future revision of approved TPL-001-4. However, the scope of this project did not allow for changes to TPL standards. Requirement R4 of proposed IRO-017-1 does not state that a planner must coordinate outages – it states that planners must resolve potential conflicts that appear in its assessments and include the Reliability Coordinator in such a process.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 States:"R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities." In response to R9, Oncor recommend s that the requirement to make it mandatory for BA's and TOP's to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES.

Organization	Yes or No	Question 7 Comments
		R10 as proposed requires each "Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area". The ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001-3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10 be reworded to provide flexibility for region structure. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.

Response: Due to comments received from a number of entities in the first posting, the term 'negatively' was removed as it was open to interpretation and superfluous. The SDT continues to agree with this approach. No change made.

Requirement R10 does not stipulate that an entity install equipment for the purposes of monitoring neighboring Transmission Operator SOLs. Monitoring can be accomplished in a number of ways including utilizing existing data links with its Reliability Coordinator or neighboring Transmission Operators to receive the status of neighboring facilities and associated flows that could impact Facilities within the Transmission Operator Area. The SDT believes that Transmission Operators need such data in order to have its models solve and for its analysis methods to be valid and also believes that the majority of Transmission Operators are

Organization	Yes or No	Question 7 Comments
already doing this to some extent. Therefore, it does not see this requirement as placing any undue burden or cost on Transmission Operators. The SDT has re-structured the requirement for greater clarity based on industry comments. See summary for wording. Based on approved FAC-011-2 Requirement R3, Part 3.7, the Reliability Coordinator has the responsibility to develop an SOL Methodology which includes defining IROL and associated T_v. The Reliability Coordinator is always the arbiter of disputes of this nature. No change made.		
SPP Standards Review Group Kansas City Power & Light	No	R1 - We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Transmission Operator takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R1 specifically to those entities identified in Requirements R3 and R4. We recommend the following rewrite: 'Each Transmission Operator shall act, or direct others as identified in Requirements R3 and R4 to act, by issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.' R2 - We have concerns regarding the phrase 'to ensure the reliability'. The phrase is ambiguous and detracts from the purpose of the standard which is to ensure the Balancing Authority takes action or directs others to act. Additionally, we suggest tying the 'others' in Requirement R2 specifically to those entities identified in Requirements R5 and R6. We recommend the following rewrite: 'Each Balancing Authority shall act, or direct others as identified in Requirements R5 and R6 to act, by issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.' R9 - We feel that the use of impacted interconnected entities is too broad for the notification requirement. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Additionally, the term 'NERC registered' in Requirement R9 and Measure M9 should be deleted. This term was deleted in IRO-008-2, Requirement R4 and TOP-002-4,

Organization	Yes or No	Question 7 Comments
		Requirement R3. We recommend rewording the requirement to read: 'Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities lasting 30 minutes or longer.' Should Requirement R9 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R10 - We have concerns with the existing language in Requirement R10 which when applied in the real-world of today's audit teams sometimes gets pushed beyond reason. For example, just how much of a neighboring TOP Area does a TOP have to model in order to determine impacts on SOLs within its TOP Area? What prevents an auditor from claiming that a TOP didn't model enough of the neighboring TOP's Area? Isn't this really the function of the RC and aren't we forcing the TOP to assume some of the RC functions with such a requirement? At the very least, we recommend the following language: 'Each Transmission Operator shall monitor 10.1 Facilities within its TOP Area,10.2 status of Special Protection Systems identified as necessary by the Transmission Operator,10.3 sub-100 kV facilities identified as necessary by the Transmission Operator, and10.4 Facilities within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator as necessary to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.' Rationale Box for R14 - The newly inserted sentence in Rationale Box for R14 doesn't completely present the overall picture of the Operating Plan as contained in the Associated Documents at the back of the standard. We propose an additional sentence, as indicated below, be included in the Rationale Box.'...These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments (OPA) required per proposed TOP-002-4 or

Organization	Yes or No	Question 7 Comments
		other assessments. The Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). The intent is not to have a...' R18 - Should Requirement R18 be split into two separate requirements, one for the Transmission Operator and one for the Balancing Authority as was done with Requirements R1 and R2 and Requirements R19 and R20? R19 - Delete the parenthetical Balancing Authority in Requirement R19. R20 - Delete Transmission Operator and the parentheses around Balancing Authority in Requirement R20.
Response: The SDT has revised the requirements to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. The SDT agrees and has revised Requirements R1 and R2 accordingly. See summary for wording. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. The SDT believes that the suggested wording is unnecessary redundancy and that it is clear from reading the standard as a whole what entities are applicable. No change made. The SDT believes the current language accurately reflects the reliability need and absent a suggested replacement sees no reason to change the proposed language. The SDT also believes that the use of the term 'impacted' should alleviate concerns over momentary outages as such outages are unlikely to impact others. No change made. The SDT believes that the professional judgment of the Transmission Operator should be the overriding factor in determining how much of a neighboring system that it needs to monitor with the principal reasoning being to monitor status and flows of key external facilities that impact Transmission Operator Facilities and that any attempt to legislate how far to go is unworkable in a standard. The SDT also believes that some degree of monitoring of neighboring systems is required for models and analysis to work correctly and that Transmission Operators are already doing this type of work. Monitoring does not imply that the Transmission Operator is usurping the wide area responsibilities of the Reliability Coordinator – it only implies that a Transmission Operator must have some		

Organization	Yes or No	Question 7 Comments
degree of visibility outside its own footprint in order to fulfill its reliability responsibilities. The SDT has re-structured the requirement for greater clarity. See summary for wording. The SDT agrees and has added the suggested sentence to the rationale box. The SDT does not believe that the suggested change adds clarity. No change made. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R1 and R2 - Southern understands other commenter's concerns about BAs, GOPs, DPs, and LSEs not falling into a Transmission Operator's TOP Area, but Southern disagrees with the approach taken by the SDT to address these concerns. Rather than removing "within its TOP Area" in R1 and "within its BA Area" in R2, the requirement should spell out the entities to link to R4 and R5. Suggested change as follows: R1 - Each Transmission Operator shall act, or direct its Balancing Authorities, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R2 - Each Balancing Authority shall act, or direct its Transmission Operators, Generator Operators, Distribution Providers, and Load Serving Entities to act by issuing Operating Instructions, to ensure reliability within its Balancing Authority Area. [Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations] R10 begins with 'Each Transmission Operator shall monitor Facilities...' Southern suggest that the words, "Bulk Electric System" be added to R10 so that it reads 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", consistent with the verbiage in IRO-003-2 Requirement 1. Measure 10 should also be changed accordingly. R10 - Southern suggest that utilization of the words, "as necessary" makes the requirement confusing and proposes the below verbiage to add clarity: 'Each Transmission Operator shall monitor "Bulk Electric System Facilities", the status of Special Protection Systems, and sub-100 kV facilities identified by the Transmission

Organization	Yes or No	Question 7 Comments
		Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas, “as being necessary to determine” any System Operating Limit (SOL) exceedances within its Transmission Operator Area.’ Measure 10 should also be changed accordingly. R15 - Southern appreciates the SDT’s consideration of Southern’s comments but disagrees that the Requirement as currently drafted, does not reflect “past tense” with respect to actions taken. Southern suggest that the SDT reword the Requirement for clarification purposes: ’Each Transmission Operator shall inform its Reliability Coordinator of its actions taken to return the system to within limits when a SOL has been exceeded.’
Response: The SDT agrees and has revised the requirements accordingly. See summary for wording. The use of the capitalized term ‘Facilities’ means that the requirement phrase is for the BES. Therefore, the SDT believes that the suggested change would be redundant and possibly create confusion. The SDT has re-structured the requirement for greater clarity. See summary for wording. The SDT received multiple comments concerning Requirement R10 and has re-structured the requirement based on all comments received. See summary for wording. The SDT has made the suggested change for consistency in wording. See summary for wording.		
CPS Energy	No	R1, in general, change to only require TOP to have the authority to act, or direct others to act, R10, in general, regarding monitoring Facilities reaching into a neighboring TOP area needs clarifying...best to delete neighboring areas wording.
Response: The SDT received a number of comments on the wording of Requirement R1 and has revised the language accordingly which should serve to alleviate your concerns. See summary for wording. The SDT has re-structured the requirement for greater clarity based on numerous industry comments. See summary for wording.		

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Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: ”Each TOP shall act or issue Operating Instructions to entities, as necessary, within its TOP Area to ensure the reliability of its TOP Area.” We believe “within its TOP Area” is necessary within the context of the standard. Requirements R3 and R4 appear to imply that Operating Instructions from a TOP are within the bounds of the TOP area only. However, by removing this language, it is our view that the TOP could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R2: Duke Energy suggests re-writing R2 as follows: ”Each BA shall act or issue Operating Instructions to entities , as necessary, within its BA Area, as necessary, to ensure the reliability of its BA Area.” We believe “within its BA Area” is necessary within the context of the standard. Requirements R5 and R6 appear to imply that Operating Instructions from a BA are within the bounds of the BA area only. However, by removing this language, it is our view that the BA could issue Operating Instructions to entities outside the TOP Area which is in direct conflict of the NERC Functional Model. R3-R6: No Comments R7: While Duke Energy believes that this is a great operational expectation or operating practice for a TOP, we believe that the requirement “as written” is unmeasurable. We believe it will be difficult for an auditor to measure how a TOP verified that another TOP implemented “its emergency procedures”. The term “emergency procedures” is too vague and subject to interpretation. For example, at what point in another TOP’s emergency procedures should a TOP provide assistance? Based on this language, we suggest removing R7 from this standard or adding this to a guidance document to promote operational excellence within the industry. R8: Duke Energy suggests re-writing R8 as follows: ”Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities and other

Organization	Yes or No	Question 7 Comments
		impacted Transmission Operators, of its actual or expected operations that result in, or could result in a known Emergency." R9-R12: No Comments R13: Duke Energy still agrees with the intent of the SDT and the modifications made. However, we ask that the SDT review and describe the expectations for outages of an TOP's Energy Management System during planned outages (data base modifications, model changes, etc.) and reconsider whether 30 minutes is an adequate amount of time to make those modifications. R14-R20: No Comments
Response: The SDT has revised the wording of Requirements R1 and R2 to address your concerns and those of others. See summary for wording. The SDT believes that the requested Transmission Operator will ascertain whether the requesting entity has implemented its procedures as part of normal operations dialogue. No change made. The SDT does not believe that the suggested change adds clarity. No change made. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
American Electric Power	No	R9: The reference "impacted interconnected NERC registered entities" needs to be consistent with the R8 terminology. We request that it be changed to "known impacted interconnected entities". R10: The reference"sub-100 kV facilities identified as necessary by the Transmission Operator" needs to be clarified. Specifically, the phrase "as necessary" is ambiguous and subject to interpretation. Our negative vote is driven solely by the ambiguous

Organization	Yes or No	Question 7 Comments
		reference “sub-100 kV facilities identified as necessary by the Transmission Operator”.
Response: The term ‘NERC registered’ has been deleted. See summary for wording. Due to this comment and those of others, the SDT has revised the wording of the requirement to replace ‘sub-100 kV’ with the term ‘non-BES facilities’ to clarify the drafting team’s intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. This non-substantive clarifying change has been made in several other standards for consistency purposes – TOP-003-3, IRO-002-4, and IRO-010-2. The SDT has also re-structured the requirement for greater clarity. However, the SDT believes that the Transmission Operator is the only one who can determine which non-BES facilities it needs to monitor and any attempt to mandate a specific coverage would be unworkable. See summary for wording.		
Northeast Power Coordinating Council Hydro One	No	Regarding Requirements R1 and R2, “ensure” should not be used as mentioned in previous comments. This must be honored THROUGHOUT the standard. For this particular requirement, consider using the word “maintain” or “restore” instead. Throughout the standard, consider replacing “address” with “maintain”. The Time Horizon should not include Operations Planning, or Same-Day Operations. The phrase, ‘within its TOP/BA Area’ should not be removed. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. Regarding Requirement R3, Time Horizons should not include Operations Planning, or Same-Day Operations. Regarding ALL the standard’s requirements, where Operating Instruction is used, the Time Horizon category must be reviewed. In Requirement R7, the “e” in emergency must be capitalized. “Comparable” should be added before “assistance”. In R7, the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it

Organization	Yes or No	Question 7 Comments
		from the previous requirements. To address the Drafting Team response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. The previous language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency. In Requirement R9, strike the words “interconnected NERC registered” to be consistent with TOP-002-4 Requirement R3. The language in Requirement R16 should be made consistent with the language in Requirement R9. There should be consistent language used in requirements R9, R16, and R17. During the last posting, a concern was expressed over the ambiguity in R9 as the words “between the affected entities” can be interpreted as any two entities (external to the one who is notifying others) that are affected by the outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. To clarify the intent of the requirement, suggest R9 be revised to: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of outages of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between THEM AND the impacted entities. Regarding Requirement R10, a Transmission Operator cannot be held responsible for monitoring ANY facilities in neighboring Transmission Operator areas. A Transmission Operator can only rely on what information is provided by a neighboring Transmission Operator. The new requirement R19 addresses the data exchange capabilities needed. The Drafting Team should consider removing R10. If Requirement R10 is to remain, then if a sub-100 kV facility is needed to maintain reliability, it should be included in the BES by exception. This standard should require the TOP to monitor BES Elements in its area. Monitoring BES Elements beyond that is the responsibility of the RC. Monitoring of neighboring facilities presents an

Organization	Yes or No	Question 7 Comments
		authority issue, which is clearly defined in the IERP Report, and Paragraphs 84 and 87 of the NOPR. R10 as written implies the TOP needs to monitor its neighboring TOP's entire area when in reality a subset of facilities may be all that is required. One suggested rephrasing is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area and those Facilities it determines as necessary in its neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area... Another suggestion is: Each Transmission Operator shall monitor Facilities within its Transmission Operator Area including sub-100kV facilities needed to maintain reliability and the status of Special Protection Systems within its Transmission Operator Area and neighboring Transmission Operator Areas to maintain reliability within its Transmission Operator Area. The Drafting Team should consider removing "ensure" or its replacement word from Requirement R11. Refer to standard PRC-001-1.1. Requirement R13 should be reworded to: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The "s" in system should be capitalized in Requirement R15. The word "own" should not be deleted from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. "Always" should be removed from Requirement R18. In Requirement R19 "(Balancing Authority Area)" is not needed and should be removed. In Requirement R20 remove "(Balancing Authority Area)" and "Transmission Operator Area". What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility several Transmission Operator Areas away from a Transmission Operator Area impacts that Transmission Operator Area.

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Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. See summary for wording. The SDT has deleted Operations Planning from the Time Horizon for all requirements in this standard as Operating Instructions are issued in a Real-time environment. However, the SDT believes that Same-Day Operations are sufficiently Real-time oriented and has retained that term.

The SDT believes that the wording of Requirement R3 as currently stated is correct. However, due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording.

The SDT agrees and has capitalized the 'e' in Emergency. See summary for wording. However, the SDT does not agree with the return of 'comparable'. The SDT believes that this term is unmeasurable and open to interpretation.

The SDT has revised Requirement R9. See summary for wording.

The SDT does not believe that there needs to be a one-to-one correspondence between the language in Requirements R9, R16, and R17 as they are addressing different topics. No change made.

The SDT does not believe that the suggested change adds clarity to Requirement R9. No change made.

The SDT has revised the wording of Requirement R10 concerning sub-100 kV facilities to clarify the drafting team's intent. The SDT believes that the non-BES terminology must be maintained in order for the SDT to be responsive to the FERC NOPR, SW Outage Report recommendations, and the IERP recommendations. The SDT has also re-structured the requirement for greater clarity. See summary for wording. However, the SDT disagrees that the current wording requires a Transmission Operator to monitor all of its neighbor's facilities.

The SDT has removed 'ensure' from the requirement. See summary for wording.

The SDT does not believe that the suggested change adds clarity to Requirement R13. No change made.

As 'System' includes distribution as per the definition in the NERC Glossary, the SDT disagrees that 's' should be capitalized. No change made.

The SDT continues to believe that 'own' is superfluous and is not needed in the requirement language. No change made.

The SDT agrees that 'always' is superfluous and provides no value or clarity. See summary for wording.

The SDT has corrected the typo in Requirements R19 and R20.

Organization	Yes or No	Question 7 Comments
The SDT believes that a Transmission Operator is in the best position to determine how far out it needs to go, i.e., what its neighbors are. The SDT agrees that events several areas away can impact an entity and for that reason has used 'neighbors' instead of 'adjacent'. The professional judgment of the Transmission Operator should determine what a neighbor is.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration. 1. Requirement R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator in its notification protocol] of its inability to perform an Operating Instruction issued by its Transmission Operator..." 2. Requirement R6 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Balancing Authority of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst suggests the following language for consideration. (i) "Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority in its notification protocol] of its inability to perform an Operating Instruction issued by that Balancing Authority."
Response: The SDT believes it is understood that entities should begin initiating actions per an Operating Instruction immediately and if the entity realizes it cannot implement the instruction(s) for any of the reasons in Requirement R2, it should immediately notify the Reliability Coordinator. The SDT agrees that an Operating Instruction may include a timeframe given by the Reliability Coordinator, but defining a generic timeframe is not necessary, or appropriate, for a requirement. No change made.		

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Seattle City Light	No	SCL appreciates the efforts of the Standard Drafting Team to increase the clarity of the TOP and IRO Standards while generally reducing the burden of compliance documentation. However for TOP-001-3, SCL believes a changes are required before this Standard provides the clarity and effectiveness of the others. Specifically SCL asks for changes as follow: Requirement R9 covers too broad a scope to be useful. The phrase "...outage of telemetering equipment, control equipment, monitoring and assessment capabilities and associated communication channels..." is all encompassing. If each BA or TOP was calling the RC every time there was the slightest glitch with telemetering or every time an ICCP link, microwave channel or EIDE data signal was cycled for maintenance or some type of momentary signal fade, the RC's phone would be ringing continually. The intent of this requirement is to be sure all entities are aware of a loss of situation awareness. This risk associated with this is not of a momentary nature and a time qualifier should be used. Using the 30 minute time requirement that is used for R13 (as written, but also see below) is sufficient to meet the intent. SCL suggests the following re-wording:R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected NERC registered entities of any scheduled and sustained outages of equipment or assessment capabilities that prevent Real-time Assessment for 30 minutes. Requirement R13, SCL suggests changing 30 minutes to 60 minutes. Usually generation, load and interchange are estimates and adjusted on hourly basis so performing assessment every 30 minutes is not necessary and could prove an onerous requirement for TOPs without providing any real reliability benefits. SCL suggests the following re-wording:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 60 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]
Response: The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made.		

Organization	Yes or No	Question 7 Comments
The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
Electric Reliability Council of Texas, Inc.	No	Similar to comments provided for IRO-001 R1, ERCOT recommends maintaining existing TOP-001-1a R1 language as much as possible as follows: "Each Transmission Operator shall have clear decision-making authority to act and to direct actions to be taken by other entities to preserve the reliability of its Transmission Operator Area and shall exercise specific authority to prevent or mitigate operating emergencies without delay, but no longer than 30 minutes. [Violation Risk Factor: High][Time Horizon: Real-time Operations]". This would preserve the original purpose of the requirement, address NOPR paragraph 64, be consistent with IRO-001 R1, and provide a timeliness requirement where appropriate for all requirements that require action by a TOP in real time without redundancy. R2 should be applied consistent to these changes as well. For R14, the current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. Please refer to previously provided comments for IRO-001 related to the use of the defined term "Operating Instruction" outside of real time. We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the BAL standards and hence a future assessment of creating such a BAL standard will be conducted.

Organization	Yes or No	Question 7 Comments
Response: The SDT disagrees that such a requirement is still needed in today's environment and the proposed revision is consistent with recommendations in the IERP report. Furthermore, the SDT believes that the suggested wording does not add clarity to the situation and may actually create confusion as there are too many objectives being covered in one sentence. However, the SDT has revised the wording of Requirements R1 and R2 to address industry comments. See summary for wording. The SDT does not understand the comment as written and is unable to find a comment from ERCOT for proposed IRO-008-2 for this topic. The SDT agrees and has deleted Operations Planning from Time Horizons for all requirements dealing with Operating Instructions. The SDT has already informed NERC management of the need for a future project to separate the Balancing Authority from the TOP standards.		
New York Independent System Operator (NYISO)	No	The NYISO has a concern with the term ensure. We suggest revising the phase to, 'maintain the reliability of it's...' R1/R2: The NYISO does not support the removal of the phrase, ' within it's TOP/BA Area'. Entities do not have authority to direct others outside of their area. In addition R3 only requires those to comply that are in the TOP/BA Area. For consistency, we suggest retaining that above language. R7: The NYISO continues to believe the previous language should be retained to limit the assistance up to and including emergency procedures implemented by the requesting entity. As worded, this could expose the assisting entity to violations for not going beyond what has been implemented. This addition would distinguish it from the previous requirements. To address the SDT response to the previous posting, when declaring an emergency, entities have a number of corrective actions to restore the system to normal. Our proposed language allows assisting entities to implement similar steps, which increase in severity, with the entity that is in the emergency.

Organization	Yes or No	Question 7 Comments
		R13: The NYISO believes that this requirement should be limited to IROL evaluations. We believe the 30 minutes were based on the requirements to be within IROL's in 30 minutes. The 30 minute assessment for SOL's may be too limiting. R16: The NYISO suggests retaining the work 'own'. This would provide clarity that this in only about the equipment the TOP owns and not other equipment. R19/20: The SDT should clarify the purpose of the bracketed entities (Balancing Authority)? The NYISO believes that R19 should be focused on TOP and R20 should be focused on BA.
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording. The SDT does not believe that the suggested change adds clarity to Requirement R3. No change made. The SDT has capitalized the 'e' in Emergency to provide additional clarity. See summary for wording. The SDT does not agree and believes that the requested Transmission Operator will discuss what procedures the requesting Transmission Operator has put in place as part of normal operating dialogue in these situations. No change made. The SDT does not agree that this requirement should be limited to IROL evaluations. The FERC NOPR made it clear that Transmission Operators should be performing SOL evaluations as well. The SDT wants to reinforce that a Real-time Assessment does not imply that all identified SOL exceedances need to be resolved within 30 minutes. SOL exceedances need to be mitigated consistent with the Transmission Operator's Operating Plan as highlighted in the SOL Exceedance White Paper. IROL exceedances would need to be mitigated consistent with the IROL T_v. No change made. The SDT disagrees and considers the adjective as unnecessary in this context. No change made. The SDT has corrected the typo in requirements R19 and R20. See summary for wording.		
NV Energy	No	The SDT has made a number of improvements to this particular standard in this latest posting. We are troubled by the following items: Definition of Real-Time Assessment contains two provisions that will make compliance with the Requirements

Organization	Yes or No	Question 7 Comments
		unattainable. First, the applicable inputs to the assessment include among other things, “known Protection System status or degradation.” Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation. Secondly, the real time assessment is to consider “identified phase angle and equipment limitations.” We are unclear as to whether this is intended to mean the identification of post-contingent standing phase angles (which current RTCA tools are ineffective at modelling and assessing) or alternatively, the identification of the angular limitations of power system equipment, such as sync check permission settings for circuit breakers. Such analyses are more readily conducted using on line power flow tools, and do not lend themselves to the real-time environment. We understand that the insertion of the modifier “applicable” may provide some relief in these considerations, but we fear that compliance enforcement will not allow discretion as to what inputs are applicable and which are not. We appreciate the significant improvement with regard to the language in Requirement R10.With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would suggest the following: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform with this R13 language.

Response: The inclusion of phase angle and Special Projection Scheme status is based on FERC NOPR and Southwest Outage recommendations. The SDT felt it was more prudent to include these items as part of the Real-time Assessment definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of Protection Systems and/or phase angles. Modeling and assessment of Special Protection Schemes and/or phase angles would be supported by Operating Plans. For

Organization	Yes or No	Question 7 Comments
example, an Operating Plan could instruct those performing a Real-time Assessment to enable/disable specific Contingencies that reflect Special Protection Scheme status (in-service or out-of-service).No change made. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
Tennessee Valley Authority	No	There should be more than one level of VSL. As currently written there seems to be no allowance for instances where entities may be operating at two different ratings (i.e. temperature-dependent ratings, directional ratings, etc.) or a period of time before the entities coordinate which rating should be used in real-time.
Response: VSL comments are addressed in q11.		
Peak Reliability	No	There still needs to be clarity about conflicting Operating Instructions. For example, if TOP 1 gives and Operating Instruction to TOP 2 and then TOP 3 gives an Operating Instruction to TOP 2, which one trumps? The same would be true for BAs. This creates potential conflicts for TOPs, BAs, and RCs. "within its ... Area" should not have been removed. R9: Why restrict to NERC registered entities when this term was removed from other requirements throughout the IRO/TOP revisions? R13: Should be clarified what evidence will be needed to ensure that a Real Time Assessment is performed if the entity does not perform it themselves. If an entity relies on a third party to perform the Real-Time Assessment, there should be a requirement showing that this reliance was coordinated with the third party.

Organization	Yes or No	Question 7 Comments
Response: The SDT does not believe that a Transmission Operator can deliver an Operating Instruction to another Transmission Operator. Such instructions would have to be provided by a Reliability Coordinator. However, due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording. Requirement R9 has been corrected. See summary for wording. The SDT does not believe that a requirement is necessary for this issue and that it can, and will, be handled through the measure for this requirement. No change made.		
Colorado Springs Utilities	No	We agree with Southwest Power Pool comments for this question. We were not allowed to associate with another entities comments at the beginning of this comment form so we are stating that in the questions. The following are our additional comments above and beyond what SPP's comments are. R13 - Would a tool such as a state estimator or RTCA be required to meet the Real-time Assessment definition or can it be done without "real-time" tools? Your response to our previous comments allude to the fact that all entities are currently using or contracting for such "real time" tools which is not universally true. Additional implementation period is needed and thus requested due to the time needed for budgeting and implementation of "real time" tools.
Response: The requirement does not specify how an entity will accomplish the task. RTCA would be one method but there are others. And, the requirement leaves open the possibility of aligning with a third-party to accomplish the task. Therefore, the SDT does not believe that additional implementation time is required. No change made.		
IRC Standards Review Committee	No	We do not have any concerns or comments on R19 and R20, which are added to address data exchange requirement and to achieve consistency with the proposed IRO-002-4, Requirement R2. However, we suggest that the SDT add Requirement R20 to the NERC issue data base along with requirements R2, R5, R6, R11, and R17 which the SDT agrees with our previous comment that these requirements belong to the

Organization	Yes or No	Question 7 Comments
		BAL standards and hence a future assessment of creating such a BAL standard will be conducted.
Response: The SDT has already informed NERC management of the need for a future project to separate the Balancing Authority from the TOP standards.		
Western Area Power Administration	No	Western has a concern on the use of the word ensure in R1 and R2. The concern is that whenever there is a reliability event it would be a violation of this requirement, since the TOP, in R1, or BA, in R2, didn't provide instructions that ensured the reliability of its area. We would suggest changing the last portion of R1 to '.... issuing Operating Instructions in accordance with its responsibilities as a Transmission Operator within its Transmission Operator Area.' and the last portion of R2 to '....issuing Operating Instructions in accordance with its responsibilities as a Balancing Authority within its Balancing Authority Area.'
Response: The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. Due to your comment and those of others, the SDT has restored the language concerning 'within a Transmission Operator/Balancing Authority Area". See summary for wording.		
Florida Municipal Power Agency	Yes	In R16 and R17, FMPA suggests replacing the words "to approve" with "over" to make it clear that the authority is all encompassing and that input on planned outages is required from the System Operators. In R16, FMPA suggests replacing "Real-time Assessment" with "analysis" to be consistent with the similar requirements for the RC and BA.FMPA notes that the number of contingencies to be studied is absent from the definition of Real-time Assessment, see comments on TOP-002-4.
Response: The SDT does not believe that the suggested change adds clarity. No change made. The SDT agrees and has used 'analysis' for consistency. See summary for wording. See response to TOP-002-4 for other considerations.		

Organization	Yes or No	Question 7 Comments
FRCC Operating Committee (Member Services) City of Tallahassee, TAL	Yes	The FRCC Operating Committee supports a majority of these proposed requirements. However, the OC does not support the language in new requirement R9 and finds that the mapping from current requirement (TOP-003-1 R3) is incomplete and needs to be addressed by the standard drafting team. The language in the existing TOP-003-1 R3 is more precise and should remain as is. If the SDT is attempting to address the comments from the SW Outage Report Recommendations "TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities," they should create a separate requirement to reflect the notification for loss of Real-time Assessment capabilities. At a minimum, the requirement should state "telemetering and control equipment", rather than "telemetering equipment, control equipment". This will add clarification to the type of equipment being addressed in the requirement. In addition, the word "planned" from M9 was not removed as noted in SDT responses. We also recommend removing the words "interconnected NERC Registered". The word "impacted" reflects who should be notified. The current mapping of existing TOP-003-1 R3 to TOP-001-3 R9 does not accurately reflect the original intent of TOP-003-1 R3. R19 and R20 have some inconsistencies with referencing TOPs and BAs.

Response: The SDT believes that the current language accurately reflects the intent of the requirement and is an accurate representation of existing requirements. However, the SDT agrees with the suggested change regarding telemetering and control equipment. See summary for wording.

'Planned' and 'NERC registered' have been removed from the measure. See summary for wording.

The SDT has corrected the typo in requirements R19 and R20. See summary for wording.

Organization	Yes or No	Question 7 Comments
Ameren	Yes	We are concerned that an entity may have a reportable NERC violation if Contingency Analysis is down for more than 30 minutes.
Response: The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made.		
MRO NERC Standards Review Forum	Yes	We believe that requirement R9 to notify impacted entities of planned outages of telemetering equipment, control equipment, and monitoring and assessment capabilities is too broad. Also, the current wording of the requirement would have the Balancing Authority and Transmission Operator providing notifications for all outages even those lasting only a couple of minutes or a few seconds. Therefore, we propose the following revision to R9: R9 Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted entities of "planned outages" of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities lasting 30 minutes or longer. Requirements R16 and R17 require that TOP and BA give authority to their system operators to approve planned outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels. Using the same rationale of R9, we propose to revise R16 and R17 as follow: R16 Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its monitoring, telecommunication, and Real-time Assessment capabilities. R17 Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance last 30 minutes or longer of its monitoring, telecommunications, and analysis capabilities. Similarly, IRO-002-4 requirement R2 should also be revised as follow: R2 Each Reliability Coordinator shall provide its System Operators with the authority to

Organization	Yes or No	Question 7 Comments
		approve planned outages and maintenance last 30 minutes or longer of its telecommunication, monitoring and analysis capabilities.
Response: The SDT believes that the use of the term 'impacted' obviates any concern for momentary outages or glitches as such problems would be unlikely to impact other entities. No change made. The SDT does not believe that the suggested change adds clarity. No change made.		
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
Salt River Project	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
Response: Thank you for your response.		

8. **Do you agree with the changes made to respond to industry comments to proposed TOP-002-4? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

R5. Each Balancing Authority shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s).

Organization	Yes or No	Question 8 Comments
PacifiCorp	No	: PacifiCorp cannot support the standard as proposed with the removal of the term NERC Registered from R3 and R5 given that the obligation to notify non-NERC Registered entities introduces an element of uncertainty into our notification obligations. Also, does next day require DMCC changes for Saturdays and Sundays? At least Operating Plan Analysis seems to allow for next-day analysis. Is the intention to mandate 24/7 rotating staff in control rooms?
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made. The SDT can't tell any entity how to do its job. It can only write requirements. In this case, the SDT believes that it is important for reliability to have a valid next-day analysis available. How an entity accomplishes this is up to them.		
Texas Reliability Entity	No	1) Requirement R4: Texas RE reiterates our previous comments regarding adding a new requirement for the BA to have an Operational Planning Analysis (in line with R1

Organization	Yes or No	Question 8 Comments
		language for the TOP). The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion. 2) Requirement R6: Texas RE requests the SDT consider whether the TOP should also be required to provide its Operating Plan(s) for next-day operations to the BA. The following questions are submitted to assist the SDT's assessment of our request. Without the TOP Operating Plan, how will a BA perform its assessment of delivery capability if it does not have predicted or planned transmission outages from the TOP(s)? 3) Requirement R7: Texas RE requests the SDT consider whether the BA should also be required to provide its Operating Plan(s) to TOPs. Without the BA Operating Plan, it is unclear how a TOP will perform its assessment to determine if there will be any SOL exceedances if it does not have the predicted generation dispatch and demand patterns from the BA.
Response: 1) The SDT does not believe that the Balancing Authority can perform an Operational Planning Analysis given the proposed definition. Nor does the SDT believe that the Balancing Authority needs to perform a special analysis in order to fulfill its responsibilities. There are mechanisms already in place in the BAL standards that allow the Balancing Authority to monitor and react to the proposed situations. In addition, the Reliability Coordinator and Transmission Operator would be monitoring the system and coordinating with the Balancing Authority as needed. No change made. 2) Since the Transmission Operator's Operating Plan may contain confidential Transmission information that a Balancing Authority can't see, the SDT believes that submittal of the plan to the Reliability Coordinator is the correct mechanism. If there are situations that arise where there are potential conflicts between the plans of the Transmission Operator and Balancing Authority, the SDT believes that the role of the Reliability Coordinator, both in this standard and in proposed IRO-017-1, will take care of those situations. In addition, the SDT points to proposed TOP-003-3 in which Transmission Operators and balancing Authorities can exchange information through the data specification concept. No change made. 3) See response to item 2. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	In R1, the OC Review Group suggests adding the word "identified" before "SOLs" to clarify transmission operators are operating to the identified SOLs. Suggested

Organization	Yes or No	Question 8 Comments
South Carolina Electric and Gas		Wording: “R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its identified System Operating Limits (SOLs).”
Georgia Transmission Corporation	No	In R1, the GSOC suggests adding the word “identified” before “SOLs” to clarify transmission operators are operating to the identified SOLs. Suggested Wording: “R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its identified System Operating Limits (SOLs).”
Response: The SDT believes the suggestion does not add clarity. No change made.		
Bonneville Power Administration	No	BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement.
Response: The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		
Hydro-Quebec TransEnergie	No	In R1, replace "shall have an Operational Planning Analysis" by "shall perform an Operational..." In R2, replace "as required in Requirement R1" by "performed in requirement R1" for consistency with M2.Do not capitalize "requirement" since it is not a defined term. R6: Why not put that requirement in R2? Simply add "...and provide that plan to its Reliability Coordinator" to the end of R2 (same for R7). The standard would be more clear and concise.

Organization	Yes or No	Question 8 Comments
		Compliance section 1.2: As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0). Table of Compliance Elements : See comment made for TOP-001-3 Associated Documents: The content of the white paper shouldn't be included in the standard. A reference with a hyperlink would be enough.
Response: R1 – The SDT disagrees. The present wording allows for an entity to use an existing Operational Planning Analysis if it is still pertinent. The SDT believes this flexibility relieves the entity of a possible undue burden. The suggested language would not allow for such flexibility. No change made. R2 – The SDT believes the present wording is correct given the explanation in item 1 above. It is standard procedure in Reliability Standards to capitalize the word 'Requirement' when it is used within a requirement. No change made. R6 – The SDT believes that the suggested consolidation would create a single requirement that contains two actions (a compound requirement) which SDT Guidelines state should be avoided. No change made. The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made. See response to TOP-001-3. The SOL Exceedance White Paper is background material that pieces together existing requirements across FAC, TOP, and IRO standards and is not a necessary ingredient as part of the TOP standard. The SDT believes that the requirements are sufficiently robust to stand-alone and that the White Paper is just corroborating material. No change made.		
Florida Municipal Power Agency	No	It seems the SDT did not understand FMPA's previous comment regarding R1. FMPA's comment was not concerning ratings or the determination of SOLs, it was concerning the contingencies to be studied in the Operational Planning Analysis (OPA). The phrase "N-1 Contingency planning" no longer exists with the revisions to these standards, and the number of contingencies to be studied is not described in the definition of Operational Planning Analysis. So, is the TOP's OPA supposed to consider

Organization	Yes or No	Question 8 Comments
		N-2 events? N-3? Loss of an entire substation? It should be clear that the level of contingencies studied in the OPA is the same level of contingencies studied to determine SOLs, thus our suggestion to refer to the performance requirements in FAC-011 or to add the phrase “in accordance with its RC’s SOL Methodology”. Otherwise, the OPA could show an exceedance of an SOL due to a contingency scenario that was not required to be considered in determining that SOL. As written, R1 is left open to interpretation, may not be measureable, and could set more stringent BES performance criteria than is already contained in the standards.
Response: The SDT does not want to be overly prescriptive. The Transmission Operator has the obligation to preserve the reliability of the interconnected Transmission system. The Contingencies to be handled in an Operational Planning Analysis are laid out in the Reliability Coordinator’s SOL methodology and the SDT expects that an entity will adhere to that methodology when performing its Operational Planning Analysis. No change made.		
MidAmerican Energy Company	No	MidAmerican remains concerned that the real-time assessment and operational planning assessment definitions as written will be wrongly interpreted to require things a real-time assessment tool cannot perform or an operational planning assessment cannot comply with. Real-time Assessment tools are not dynamic assessment tools and do not inherently understand phase angle impacts nor stability as suggested by the inclusion of Protection System status, degradation, and identified phase angle / equipment limitations. The SDT could check with real-time assessment vendors and verify that the revised definitions match the capabilities of real-time assessment tools and adjust the proposed definition. At a minimum, the SDT needs to clarify / modify words in the definition to ensure that real-time assessment tools can be compliant. Suggested clarifications include: Real-time assessment means a steady state analysis of thermal and voltage impacts. Power system transients, dynamics, nor actual phase angles are required. Protection Systems in the case of Real-time Assessment means the accurate system topology representation of normal protection system clearing (e.g. a three-terminal line as a single N-1 next worse contingency).Identified phase angles and equipment limits are identified in-terms of equipment ratings (amps, MVA, etc.). Phase angle inputs (from PMU’s etc.) or phase

Organization	Yes or No	Question 8 Comments
		angle calculations are not required. Further, personnel cannot be substituted for Real-time Assessments tools due to the 30 minute limitations imposed. Power system transient or dynamic analyses using real-time data can be time consuming to construct and run. At most, only a few power system dynamic analyses can be performed in the space of 30 minutes and may not keep pace with changing real-time conditions. Removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3 opens the requirement scope to an un-provable state and potential non-compliance. MidAmerican suggests the modifier “NERC registered” be restored in front of “entities.”
Response: The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated “applicable” based on industry feedback and believes that the proposed definition reflects an entity’s responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term ‘applicable’ was intended to capture that intent and to protect an entity against unreasonable expectations. No change made. There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term ‘NERC registered entities’ is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
Duke Energy	No	R1: Duke Energy suggests re-writing R1 as follows: ”Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any identified System Operating Limits (SOLs).”We believe the addition of “identified” adds additional clarity and conforms to the language in FAC-011.

Organization	Yes or No	Question 8 Comments
		R2: Duke Energy requests clarification on whether a process for each SOL exceedance identified in the Operational Planning Analysis is necessary or is one document that address any and all exceedances of SOL(s) is acceptable? R3: Duke Energy believes "impacted" is not needed in the context of the requirement and suggests removal. R4: No Comment R5: Duke Energy believes "impacted" is not needed in the context of the requirement and suggests removal. R6/R7:Duke Energy suggests the following for R6:"Each Transmission Operator shall provide the results of its Operating Planning Analysis for next-day operations identified in Requirement R2 to its Reliability Coordinator." We also believe that R6 and R7 goes beyond the scope of Recommendation 1 of the SW Outage Report. The report indicates that TOPs should share the results with neighboring TOPs and RCs, and not necessarily the Operating Plan itself. In addition, the BA is not cited in Recommendation 1 of the SW Outage Report as having to do the same type of analysis.
Response: R1 - The SDT believes the suggestion does not add clarity. No change made. R2 – The SDT outlined its beliefs on this matter in the associated explanation of Operating Plan which appears in Section F of the proposed standard. R5 – The SDT agrees and has made the suggested change. See summary for wording. R6/R7 – The SDT believes that simply providing the results could be potentially misleading and that it would be better for reliability to provide the entire plan. While the SDT agrees that the SW Outage report did not specifically spell out the Balancing Authority, that inclusion of the Balancing Authority is consistent with the over-all approach of the project standards and makes sense for reliability. No change made.		
Xcel Energy	No	R2 - is the descriptor "potential" needed?

Organization	Yes or No	Question 8 Comments
		Do R6 & R7 need a qualifier "...by the time frame established by the RC"?

Response: The SDT believes that since the requirement is dealing with next-day operations that haven't happened, that the use of 'potential' is correct and needed. No change made.

The SDT believes that the Transmission Operator/Balancing Authority will coordinate with the Reliability Coordinator as to when the plans need to be submitted and that placing such language in a requirement is unnecessary and could be detrimental. No change made.

Organization	Yes or No	Question 8 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	R3 - It is not clear why the SDT removed the qualifier "NERC registered". Southern recommends adding "NERC registered" back to the requirement. The NERC registered entities have established a reliability relationship with the RC, TOP, and BA and should be notified per this requirement. R5 - See comment regarding removal of "NERC Registered" for R3. Also, in the SDT's consideration of our previous comments, the SDT states they do not believe R5 requires notification. Given R5 clearly states that the BA shall notify impacted entities, it is not clear what the SDT's expectation / interpretation of this requirement is. Southern suggests modifying the requirement to incorporate the concept that notification from the BA is only required to entities where the BA is requesting an action that is different than what the entity provided to the BA. For example, if a GOP provided their expected generation resource commitment and dispatch to the BA, the BA reviews the information and determines that this particular GOP needed to commit additional units to provide more regulation, frequency response, etc., then the BA should notify this GOP. If another GOP provided data and the BA did not have any suggested changes, then there should not be a notification requirement. Suggested changes are as follows: "Each Balancing Authority shall notify NERC registered entities identified in the Operating Plan(s) cited in Requirement R4 when the BA is requesting the entity to take an action that is different from the last submitted plan the entity originally provided to the BA."

Organization	Yes or No	Question 8 Comments
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made. The SDT disagrees and believes that specific notifications should be delivered for each day's Operating Plan. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	R4 - We suggest that load forecast uncertainty and resource uncertainty be added to the list of Parts for Requirement R4.1.3 Data Retention - Hyphenate 90-calendar days in 1.3 Data Retention for consistency with the other standards in this package.
Response: The SDT believes that uncertainty can be handled within the existing requirement language in Requirement R4, Parts 4.1 and 4.3. No change made. The SDT agrees and has corrected the typos.		
Electric Reliability Council of Texas, Inc.	No	The current definition of Operating Plan states "a document". Please refer to previous comments for IRO-008 related to this issue. For R3 and R5, please see previously provided comments for IRO-008 R4.For R4, the SDT should consider consistency of use of "Demand patterns" and "Load Forecast".
Response: See response to IRO-008-2 comment. Without a specific reference for consistency, the SDT believes that the current language is correct. No change made.		
Northeast Power Coordinating Council Hydro One	No	The proposed definition for Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a redline of what is in the NERC Glossary. The Rationale for Requirement R1 can be removed, and be placed in a guideline or support document.

Organization	Yes or No	Question 8 Comments
		The Rationale for Requirement R3, and Rationale for Requirements R4 and R5 can be removed. It belongs in Consideration of Comments. The Rationale for Requirements R6 and R7 can be removed, and be placed in a guideline or support document.
Response: Due to the extensive changes made to the two definitions, the SDT believes that it would have caused considerable confusion if a redlined version had been supplied. No change made.		
Northern Indiana Public Service Company (NIPSCO)	No	TOP-002-4 R1 requires that you perform an analysis that identifies SOL exceedances, but SOLs are not explicitly included as a study input in the Operational Planning Analysis definition, only Facility Ratings, which are only a subset of FAC-014-2 R2 SOLs. There seems to be operating plans created by the TOP in R2 and operating plans created by the RC in IRO-008-2. How are conflicts resolved if the results differ? How does the R2 Operating Plan mesh with the operating plan specified in VAR-001-4 R1? Are they the same?
Response: The SDT believes that if an entity observes its applicable Facility Ratings in pre- and post-Contingency situations that it will avoid SOL exceedances since SOLs are based on Facility Ratings. The SDT believes that there are existing protocols for resolving conflicts and that the exchange of Operating Plans required by these proposed standards facilitate the identification of any potential conflicts and start the conflict resolution process. No change made. The SDT believes that the plan cited in VAR-001-4 Requirement R1 would be one part of the Operating Plan cited in this proposed standard.		
NV Energy	No	We are troubled by the removal of the limiter “NERC registered” in reference to the entities that are to be notified under R3. This unnecessarily opens the requirement scope to an un-provable state. Suggest restoring the modifier “NERC registered” in front of “entities.”

Organization	Yes or No	Question 8 Comments
Response: There are entities that fulfill the functional roles as described in the Functional Model which are not necessarily registered at NERC. This is especially true for some entities in the Canadian provinces. If the term 'NERC registered entities' is used those unregistered entities would not be included in the requirements. Removing that specific language includes those unregistered entities. No change made.		
Puget Sound Energy		The language of measure M2 is inconsistent with requirement R2 - it is missing the word "exceedance" after the phrase "System Operating Limits (SOLs)".
Response: The SDT agrees and has made the suggested change to ensure consistency. See summary for wording.		
MRO NERC Standards Review Forum Lincoln Electric	Yes	As currently drafted, R6 would require the Transmission Operator to provide its Operating Plan to the Reliability Coordinator every day (next day studies) regardless of whether the Plan is modified or not. To prevent unnecessary duplication as well as allow for greater flexibility in the requirement, recommend modifying R6 as follows to allow the Transmission Operators and Reliability Coordinators to develop an arrangement or schedule.R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator in accordance with the Reliability Coordinator's schedule.
Response: The SDT disagrees with the commenter's statement. The present wording allows for an entity to use an existing Operational Planning Analysis if it is still pertinent. The SDT believes this flexibility relieves the entity of a possible undue burden. The suggested language would not allow for such flexibility. No change made.		
Ameren	Yes	Our Daily Analysis supplements the MISO Operational Planning Analysis and although we could rely on MISO, we have chosen to go beyond what is required.
Seattle City Light	Yes	
ACES Standards Collaborators	Yes	
NERC Compliance Policy	Yes	

Organization	Yes or No	Question 8 Comments
IRC Standards Review Committee	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Peak Reliability	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	
CenterPoint Energy Houston Electric LLC	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 8 Comments
Independent Electricity System Operator	Yes	
City of Tallahassee, TAL	Yes	
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
ReliabilityFirst	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
CPS Energy	Yes	
Response: Thank you for your support.		

9. **Do you agree with the changes made to respond to industry comments to proposed TOP-003-3? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT has made the following non-substantive changes due to industry comments:

R1, Part 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data as deemed necessary by the Transmission Operator.

Organization	Yes or No	Question 9 Comments
ACES Standards Collaborators Georgia Transmission Corporation	No	(1) The applicability section needs to be revised to remove the Load Serving Entity. The Risk Based Registration project will retire the LSE from Appendix 5B from the NERC Rules of Procedure. Having the LSE listed as an applicable entity leads to confusion and questions. For example, a reviewer of this standard could question how the RBRAG could arrive at the conclusion that LSE is not needed for reliability but this drafting team apparently determined it was needed for reliability by including it in the standard. At the very least, if the SDT is not intending to contradict the RBRAG's finding's a rationale box should state that LSE is only being included for historical purposes and will be removed pending the final approval of the RBRAG recommendations by the NERC Board of Trustees. (2) Requirement R1 is problematic because it lists sub-100 kV transmission equipment as being subject to a standard. Sub-100 kV transmission equipment are not subject to reliability standards unless they are deemed to be a part of the Bulk Electric System. A simple solution would be to remove the clause "including sub-100 kV facilities needed to make this determination." If these sub-100 kV facilities are needed for reliability they would be part of the BES inclusion process and would be covered by the NERC defined term "Facilities."

Organization	Yes or No	Question 9 Comments
		(3) For Requirements R1 and R2, we recommend changing the term "Special Protection System" to "Remedial Action Scheme" because the SDT Project 2010-05.2 has determined that RAS is more appropriate and SPS will be retired upon FERC approval. This standard would potentially have an outdated glossary term if it keeps SPS in the requirement. (4) Requirement R5 should be revised to remove the LSE function.
Response: (1) As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made. (2) The SDT has clarified its intent in revised wording. See summary for wording. (3) The term Special Protection System remains within the NERC Glossary as an approved term. If at some point in the future, this term is replaced, a change to this standard can and should be proposed to conform it to the new term. No change made (4) As previously stated, the Load-Serving Entity will be removed from all pertinent standards and requirements when the registration project is completed and approved. This activity will be a separate endeavor and will encompass all pertinent standards. The SDT does not believe that leaving the Load-Serving Entity in the applicability of these standards will cause any confusion. No change made.		
Texas Reliability Entity	No	1) Requirement R1.1: Texas RE requests that the SDT consider replacing the term "sub-100 kV" with "non-BES" to be more inclusive of those facilities where data or monitoring may be needed. For instance, the RC may choose to monitor private use networks or radial lines connected to large loads/generation connected at greater than 100 kV but are excluded from the BES, in addition to sub-100 kV facilities. This change would not be needed if it is the intent of the SDT that the reference to "sub-100 kV" facilities is for those facilities that have been intentionally included in the BES due to their criticality? 2) Requirement R2: Texas RE reiterates our previous comments about replacing "analysis functions" with "Operational Planning Analysis." This comment relates to the TOP-002-4, R4 comment for requiring a BA to have an Operational Planning

Organization	Yes or No	Question 9 Comments
		Analysis. The SDT responded to the initial comment that creation of an Operating Plan fulfills the reliability need. We continue to maintain that it appears there is a gap for the BA responsibilities. The BA must perform some type of Operational Planning Analysis in order to develop their Operating Plan for the next day. Texas RE requests the SDT further consider this suggestion.
Response: The SDT has clarified its intent in revised wording. See summary for wording. The SDT considers that "analysis functions" is an adequate description of the Balancing Authority's study process, and considers that the proposed definition of Operational Planning Analysis would require the Balancing Authority to possess information related to Transmission limitations unrelated to the act of balancing Load and resources. There is not reliability gap. No change made.		
Electric Reliability Council of Texas, Inc.	No	Additional thought should be given to the overall approach to incorporating Protection System Status. While SPSs are currently in the standards, incorporating the broader definition of Protection Systems will likely incur additional hardware, modeling, display creation, etc. ERCOT does not support its inclusion without a holistic review of its impact within the standards. At a minimum, the implementation timeframe should be extended to realize that additional time is necessary after the RC requests the data, for an entity to actually provide such data. ERCOT recommends a minimum of 24 months vs the 12 months for R3.
Response: This data concerning Protection System status is currently collected routinely and data transfer mechanisms are in place. Twelve months is a reasonable time frame to implement Requirement R3. The SDT assumes that the commenter meant to say Transmission Operator and not Reliability Coordinator. The SDT does not intend for the Transmission Operator to monitor Protection Systems rather the intent is for the equipment owner to notify the Transmission Operator when a Protection System failure could impact how the Reliability Coordinator assesses reliability, i.e., changes Contingencies that need to be studied. No change made.		
Hydro-Quebec TransEnergie	No	Compliance section 1.2 : As proposed, the section doesn't give any useful information. That section should actually serve to list the actual processes that will be used for that

Organization	Yes or No	Question 9 Comments
		particular standard. Or at least refer to the actual section of the ROP that lists the processes used (Appendix 4C, section 3.0).
Response: The Compliance section is boilerplate language supplied by NERC. The SDT did not change this boilerplate language. The SDT will pass this comment on to NERC Legal. No change made.		
Duke Energy	No	Duke Energy asks the SDT to consider adding a mechanism to allow a recipient of a request to challenge the requestor if a reliability related need cannot be established. For example, should a BA wanting to know the ACE of every BA within the Eastern Interconnection be allowed to get this information if there is not a reliability related need to have the information?
Response: The SDT is unconvinced that a requestor will consistently request data that it does not need to assure continued reliability. The SDT understands your concern but this does not rise to the level of a standard requirement. No change made.		
Ingleside Cogeneration , LP	No	ICLP agrees there are times where the TOP will need data regarding certain sub-100 kV facilities to ensure operational reliability. However, these facilities must be limited to those identified using the NERC exception process deployed concurrently with the new BES Definition. This process was developed precisely for this reason - and eliminates the possibility that the TOP can declare any sub-100 kV facility to be under their authority without justification. This opens the door to rash actions on the part of TOPs eager to close a perceived reliability gap based upon a single incident, which may or may not be reasonable. If the project team believes that the exception process is inadequate, a better solution may be found in that venue (in NERC's Rules of Procedure). ICLP would suggest that a temporary exception could be quickly granted for a concerned TOP - that a full evaluation by an independent panel would take place afterwards.
Response: Requirement R1, part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		

Organization	Yes or No	Question 9 Comments
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration.1. Requirement R1, Part 1.1 - ReliabilityFirst requests the SDT define the term “as deemed necessary” in Requirement R1, Part 1.1. ReliabilityFirst finds that the first bullet of “Section 4 - Measurability” of the NERC document titled Acceptance Criteria of a Reliability Standard states “Words and phrases such as “sufficient”, “adequate”, “be ready”, “be prepared”, “consider”, etc. should not be used.” ReliabilityFirst believes the phrase “as deemed necessary” is such a phrase, which leaves the requirement open to interpretation making it difficult to enforce and therefore, should not be used in the Standard.
Response: In Requirement R1 Part 1.1, “as deemed necessary” refers to the certain data elements that the Transmission Operator decides is needed. This would not be a measurement component of this requirement, since Requirement R1 Part 1.1 requires the publication of a list, which can be objectively measured during an audit. No change made.		
CPS Energy	No	see comments for IRO-010-2
CenterPoint Energy Houston Electric LLC	No	See comments for IRO-010-2.
Response: See response to IRO-010-2.		
Northeast Power Coordinating Council Hydro One	No	The proposed definitions for Real-time Assessment and Operational Planning Analysis shown in the Definitions of Terms Used in Standard should be a red line of what is in the NERC Glossary. Additional information should be added to the Rationale for Requirement R5 for justification and background.
Response: Since the changes to the two definitions were so extensive, the SDT believed it would be confusing to provide a redline version of the definitions. No change made. The SDT believes that the rationale provided is sufficient when taken in conjunction with the NOPR comment. No change made.		

Organization	Yes or No	Question 9 Comments
Salt River Project	No	The Requirements go way beyond the established NERC process in creating and modifying current standards. The goal is stated to create reliability standards that “use a results based approach that focuses on performance, risk management and entity capabilities”. I suggest that the requirements in TOP-003-3 do not meet this threshold in that the burdensome requirements do not result in a significant enhancement in reliability nor do they consider entity capabilities. I suggest that the SDT work on creating a simple and efficient process to verify that necessary operating data is being freely exchanged as needed among entities. A suggestion might be to create a regional committee to address those conflicts that might occur between entities. If an entity is not able to obtain necessary operating data from an entity, they could provide a report to this committee and the committee could resolve the conflict. This would allow entities to obtain the data needed and avoid the significant burden associated with this Standard.
Response: The need for data to support reliability is unquestioned in a system where multiple Balancing Authorities, Transmission Operators and Reliability Coordinators are coordinating together to preserve reliability. The proposed change would produce delays in securing the data necessary to support preserving reliability. No change made.		
Indiana Municipal Power Agency	No	The use of a documented specification for the data needed by the Transmission Operator is extremely vague and allows the inclusion of all other data needed by the current NERC standards which creates a double jeopardy issue or an instance where an entity may meet one NERC standard but violate IRO-010-2. For example, VAR-002-3 becomes effective on October 1, 2014 and does not require the notification of AVR status change if it has been restored within 30 minutes of such change. The Transmission Operator has already given notice that its manuals will reflect this change a few months after October 1, 2014. This means that Generator Operators in this TOP area will have to still give notification within 30 minutes in order not to violate IRO-010-2 even though VAR-002-3 says differently. The documented specification for data needs to exclude data that is covered by other NERC standards to prevent this from happening and to reduce the workload on entities.

Organization	Yes or No	Question 9 Comments
Response: The ability of the Reliability Coordinator to request and receive the data necessary to preserve reliability is a foundation of coordinated system operations. The suggested change would result in an unmeasurable and non-auditable standard. No change made.		
Dominion Compliance Policy	No	While Dominion acknowledges the SDT's consideration of its comments relative to inclusion of the phrase 'sub-100 kV facilities' it still disagrees with the SDT's decision to retain it in this requirement for the reasons previously stated.
Response: Requirement R1, Part 1.1 was added to directly address Recommendations # 3 and 6 of the SW Outage Report and the FERC NOPR. The SDT has clarified its intent in revised wording. See summary for wording.		
Seattle City Light	Yes	SCL appreciates the efforts of the Standard Drafting Team in crafting IRO and TOP Standards that are clearer while generally reducing the burden of compliance documentation. For TOP-003-3, while somewhat burdensome, this Standard makes the process for requiring entities to request and provide real time reliability data standardized. SCL is concerned with the implementation period allowed for this Standard, because in our experience it has taken longer than 12 months to negotiate and implement the necessary data exchange agreements between entities. As such, SCL suggests extending the periods allowed to eighteen and twenty-four months, re-wording the effective date section as follows: Section 5. Effective Date. All requirements except Requirements R5 shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved gy an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. Requirement R5 shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval

Organization	Yes or No	Question 9 Comments
		by an applicable governmental authority is required for a stand to go into effect. Where approval by an applicable governmental authority is not required, the stand shall become effective on the first day of the first calendar quarter that is twenty four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction
Response: Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
Ameren	Yes	We are concerned about the change from "Planned Outage Coordination" to "Operational Reliability Data" which as we understand deals with the specification and exchange of data for use in studies for which we find the languages confusing and needing clarification.
Response: Planned Outage Coordination is now in proposed IRO-017-1.		
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Florida Municipal Power Agency	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 9 Comments
Bonneville Power Administration	Yes	
FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Peak Reliability	Yes	
PacifiCorp	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 9 Comments
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee, TAL	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
City of Tallahassee	Yes	
Tennessee Valley Authority	Yes	
New York Independent System Operator (NYISO)	Yes	

Organization	Yes or No	Question 9 Comments
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
PJM Interconnection	Yes	
NV Energy	Yes	
Response: Thank you for your support.		

10. **Do you have any comments on the changes made to respond to industry comments on the SOL Exceedance White Paper? If so, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The SDT reviewed the submitted comments and incorporated most of the suggestions. The SDT believes the suggested changes provided clarity resulting in a better product. Changes can be seen in the redlined version of the SOL Exceedance White Paper.

Organization	Yes or No	Question 10 Comments
IRC Standards Review Committee Independent Electricity System Operator	No	During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT's response indicates that "it has revised the whitepaper to include "as necessary and appropriate". However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that "All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan." We speculate that the insertion of "as necessary and appropriate" to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, "However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating)." We urge the SDT to reassess whether or not the "as necessary and appropriate" should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.

Organization	Yes or No	Question 10 Comments
Response: The SDT agrees and has modified the White Paper as suggested.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	As currently presented, the example Operating Plan in Table 1 on page 8 of the SOL Exceedance White Paper is confusing. It is actually a pretty good attempt to capture in table form the concepts described in the document text related to the time limit is exceeded versus pre-/post- contingency. However, it uses terms such as “non-cost” and “off-cost” which are not standard industry terms and which are not used elsewhere in the document. The SDT should consider removing these terms and using more standard terms, such as re-dispatch reconfiguration, etc. as appropriate. In addition, the “Legend” shown is confusing and does not help support the example.
Response: The SDT agrees and has modified the White Paper as suggested.		
Electric Reliability Council of Texas, Inc.	Yes	During the last posting, we commented on the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded. The SDT’s response indicates that “it has revised the whitepaper to include “as necessary and appropriate”. However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that “All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.” If there is a basecase exceedance, the entity should take all actions up to and including shedding load within the timeframe to protect the equipment. If the entity is somewhere between the 4 hr. and 15 min. rating they have up to 15 min to get below the continuous (normal) rating for a basecase (pre contingency) exceedance.
Response: The SDT agrees and has modified the White Paper as suggested.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	Yes	Hyphenate 24-hour in the 8th line under 1. on Page 1. First full paragraph on Page 3, we suggest the following rewrite for the last sentence in that paragraph. ’Conversely, if an area is not at risk of instability, no Facilities are

Organization	Yes or No	Question 10 Comments
		approaching their thermal Facility Ratings but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the limiting SOLs.' We also suggest deleting the 1st sentence in the following paragraph on Page 3. The paragraph flows better without it. We further suggest the following rewording in what would then be the 2nd sentence in the paragraph. 'How an entity remains within these SOLs can vary depending on the operating practices and planning strategies employed by that entity.' In 4. Voltage Stability Limits, replace the 2nd sentence with the following: 'Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met.'

Response: The SDT has modified the White Paper to incorporate many of the proposed changes.

24-hour in the 8th line under '1.' on Page 1 has been hyphenated.

As suggested, the last sentence in the first full paragraph on page three has been modified to state, "Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs."

The first sentence in the following paragraph states, "It is important to distinguish operating practices and strategies from the SOL itself." The SDT believes this is an important statement that is critical to conveying the intent of the White Paper. No change made.

The recommendation regarding the second sentence in the in this paragraph proposes to remove the word "mechanisms" and replace it with "planning strategies". The SDT agrees that the addition of "planning strategies" adds clarity to the sentence and will accept the recommended change. However, the SDT believes that "mechanisms" are an important part of how an entity remains within the SOLs as explained in the following sentence in the White Paper. The SDT changed the sentence to state, "How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity."

As suggested, the second sentence in the voltage stability section has been modified to state, "Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage stability criteria are met."

Organization	Yes or No	Question 10 Comments
Northeast Power Coordinating Council Hydro One	Yes	In the White Paper System Operating Limit Definition and Exceedance Clarification, delete the phrase “unit/intra-area instability,” from the Transient Stability Limits description. Individual unit instability is not being looked at; operations are to prevent system instability. During the last posting, the need to shed load under the pre-contingency loading condition when the 4-hour rating is exceeded was commented on. The Drafting Team’s response indicates that “it has revised the whitepaper to include “as necessary and appropriate”. However, this change is made to the post-contingency condition for exceeding the 15-minute Emergency Rating, but not to the pre-contingency loading condition when the 4-hour rating is exceeded as it still stipulates that “All of the above plus load shed to control violation below Emergency Rating consistent with timelines identified in Operating Plan.” We speculate that the insertion of “as necessary and appropriate” to the post-contingency condition when the 15-minute Emergency rating is exceeded was an error. However, if the SDT really meant to keep load shedding under the pre-contingency loading condition when the 4-hour rating is exceeded, then we will again express our disagreement with the approach. When the 4-hour rating is exceeded, the TOP still have up to 15 minutes to reduce loading to within the Normal rating. Further, as stated in the paragraph preceding Table 1, “However, operating between 900 MVA and 950 MVA (commenter insert: i.e. exceeding the 4-hour rating but not the 15-minute rating) is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1 (commenter insert: i.e. 15 minutes have elapsed and still unable to return loading to below 4-hour rating).”We urge the SDT to reassess whether or not the “as necessary and appropriate” should be inserted to the pre-contingency loading condition for exceeding the 4-hour rating.
Response: The SDT agrees and has modified the White Paper as suggested.		
New York Independent System Operator (NYISO)	Yes	The current draft introduces the term ‘limiting SOLs’. ’For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or

Organization	Yes or No	Question 10 Comments
		post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the limiting SOLs. Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs. We believe that a better wording would be the 'limiting criteria that results in the identified SOL'.
Response: The SDT does not believe that the phrase 'limiting SOL' introduces a new term, but in order to provide additional clarity, the phrase 'limiting SOL' has been replaced with 'most limiting SOL'. The SDT chose not to adopt the proposed wording, 'limiting criteria that results in the identified SOL'. In the referenced 'for example' sentence, the Facility Ratings are the actual SOLs that are not to be exceeded pre- or post-Contingency consistent with the example provided in Figure 1. In this example scenario, the SDT views the Facility Ratings as being the 'most limiting SOLs' rather than the most 'limiting criteria'. This concept is supported by paragraph 1 on page 7 which states, "An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment: • Actual flow on a Facility is above the Facility Rating for an unacceptable time duration • Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating" No change made.		
American Electric Power	Yes	There are inconsistencies between the information provided in Figure 1 (p.5) and Table 1 (p.8) which may cause confusion. Consider for example the range of 800 to 900 MVA. In Figure 1, the Pre-Contingency flow in this range is considered "not acceptable" if longer than 4 hours. The text "not acceptable" is too strong, so rather than this language, we suggest using "action may need to be taken". The rows in Table 1 do not clearly correspond to the example in Figure 1. It would appear that Table 1 should have four rows rather than three. As a result, it is unclear exactly which of the four ranges in Figure 1 correlate to the three Operating Plans provided in Table. In Figure 1, does the 800mva (24 hr rating) refer to a Normal or Emergency facility rating, or perhaps both? Please provide clarification.

Organization	Yes or No	Question 10 Comments
Response: The phrase 'not acceptable' is simply used to distinguish two possible categorizations of system performance – acceptable versus not acceptable (or unacceptable). Given these two categorizations, in the Figure 1 example, exceeding the 4-hour emergency rating for longer than 15 minutes constitutes unacceptable system performance. The SDT chose to keep the existing language. No change made. There are four operating ranges in Figure 1 and three rows in Table 1. The bottom range in Figure 1 does not have a corresponding row in Table 1 since no Facility Rating is being exceeded in that operating range. Table 1 Row 1 corresponds to the operating range in Figure 1 between 800-900 MVA (between the green and the yellow Facility Ratings). Table 1 Row 2 corresponds to the operating range in Figure 1 between 900-950 MVA (between the yellow and the red Facility Ratings). Table 1 Row 3 corresponds to the operating range in Figure 1 above 950 MVA (above the red Facility Rating). Regarding the nature of the 800 MVA rating, item 1 on page 1 states, "A 24- hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature." No change made to Figure 1.		
FRCC Operating Committee (Member Services) City of Tallahassee, TAL Florida Municipal Power Agency	Yes	We suggest adding the following clarification to page 2 of the white paper: o Remove the terms "Normal (continuous)" from the Pre-Contingency section, example "b". We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. o Remove the terms "Emergency (short term)" from the Post-Contingency section, example "b". We recommend it read the following: b. All Facilities shall be within their applicable Facility Ratings and thermal limits. We also suggest that the paper be reviewed for consistency when using the terms "pre-contingency" and "post-contingency". Interchanging the use and context causes confusion - i.e. Change the column headers in Table 1, "Pre-Contingency Loading" to "Pre-Contingency Mitigation" and change "Post-Contingency Loading" to "Post Contingency Mitigation". Another example would be to use "Real-Time flow" instead of "Pre-Contingency Flow".

Organization	Yes or No	Question 10 Comments
		Also in Table 1, under the 'Emergency (4hr)" row - "Post Contingency Loading" column change "all" to "available".
Response: The SDT agrees with the suggestion to revise the language on page 2 in item 'b' under the pre-Contingency section and item 'b' under the post-Contingency section to state "All Facilities shall be within their applicable Facility Ratings and thermal limits". This change is justified by the subsequent clarifications in the White Paper along with the Figure 1 example which illustrates an SOL performance summary for Facility Ratings. Note 1 in Figure 1 clarifies that pre-Contingency flow is the actual MVA flow observed on the Facility through Real-time operations monitoring. The SDT reviewed the paper and verified the accuracy of the use of "pre-Contingency" and "post-Contingency". The SDT chose to maintain Table 1 column headings as "Pre-Contingency Loading" and "Post-Contingency Loading" since the purpose of the mitigation strategies contained within the table are to control loadings. However, the SDT agrees with changing "all" to "available" in Table 1, "Post-Contingency Loading" column, "Emergency (4 hr.)" row.		
Duke Energy	Yes	Duke Energy agrees with the SOL Performance Summary described in Figure 1. We believe that Figure 1 adequately describes the intent on treatment of SOL(s), more so than the text of the White Paper itself. We suggest that the SDT revise the text in the White Paper to better align with the SOL Performance Summary in Figure 1.
Response: The SDT believes the White Paper is most effective through the combination of text, tables, and figures. The SDT is willing to process specific feedback regarding White Paper text.		
Peak Reliability	Yes	The SOL Whitepaper directly addresses the confusion, debates, and misconceptions around the SOL concept that is so prevalent in the industry. Many thanks to the SDT for issuing the much needed SOL Whitepaper. Peak believes this paper will not only bring clarity and resolution to confusing and even contentious issues related to SOL establishment and exceedance, but will also result in improved reliability.
Seattle City Light	No	SCL appreciates the efforts of the Standard Drafting Team to increase clarity of the IRO and TOP Standards.
Associated Electric Cooperative, Inc. - JRO00088	No	

Organization	Yes or No	Question 10 Comments
ACES Standards Collaborators	No	
NERC Compliance Policy	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Clark Public Utilities	No	
Flathead Electric Cooperative, Inc.	No	
CenterPoint Energy Houston Electric LLC	No	
Manitoba Hydro	No	
Pepco Holdings Inc.	No	
Idaho Power Company	No	
American Transmission Company, LLC	No	
Northern Indiana Public Service Company (NIPSCO)	No	
Texas Reliability Entity	No	
Salt River Project	No	
Consumers Energy Company	No	
Oncor Electric Delivery LLC	No	
ReliabilityFirst	No	
Tennessee Valley Authority	No	

Organization	Yes or No	Question 10 Comments
Tri-State Generation and Transmission Association, Inc.	No	
Northeast Utilities	No	
Georgia Transmission Corporation	No	
CPS Energy	No	
MidAmerican Energy Company	No	
Response: Thank you for your support.		

11. **The SDT has made revisions to VRFs and VSLs as needed to conform to changes made to requirements and to respond to industry comments. Do you agree with the VRFs and VSLs for the nine posted standards? If you do not agree, please indicate specifically which standard(s) and requirement(s), and whether it is the VRF or VSLs you disagree with, and explain why.**

Summary Consideration: The SDT corrected several typos and made a grammatical change to all VSLs dealing with notification. As was pointed out in a comment, the 'syntax' of the proposed VSLs was incorrect. Instead of saying 'lesser than' it should have said 'greater than' to allow for the proper consideration of the violation. Due to the simple replacement of one word or because it was just a simple typographical correction and the volume of changes, the actual changes are only shown in the redlined standards.

The SDT has made the following changes to VSLs in response to industry comments:

IRO-008-2:

R3	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted ~~NERC registered~~ entities identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).

IRO-008-2: Requirement R4 Severe VSL - ~~The Reliability Coordinator did not perform Real-time Assessments. OR~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.

IRO-014-3:

R2	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address one of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address two of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address all three of the ~~criteria~~parts specified in Requirement R2.

IRO-014-3: Requirement R7 Severe VSL - The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator ~~has~~had implemented its emergency procedures, unless such actions could not physically be implemented or would have violated safety, equipment, regulatory, or statutory requirements.

IRO-017-1: Requirement R2 Severe VSL - The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator's outage coordination process.

TOP-001-3: Requirement R1 Severe VSL - The Transmission Operator failed to act~~, or direct others within its Transmission Operator Area to act,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

TOP-001-3: Requirement R2 Severe VSL - The Balancing Authority failed to act ~~or direct others within its Balancing Authority Area to act,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

TOP-001-3: Requirement R7 Severe VSL - The Transmission Operator did not provide assistance to other Transmission Operators, ~~if~~when requested and able, ~~when~~and the requesting entity had implemented its ~~e~~Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

TOP-001-3: Requirement R8 Severe VSL - The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators~~, whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more ~~other~~ known impacted Balancing Authorities or more 15% of the known impacted ~~other~~ Balancing Authorities~~, whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.

TOP-001-3: Requirement R9 Severe VSL - The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, monitoring and assessment capabilities, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more impacted interconnected NERC registered entities or more than 15% of the negatively impacted NERC registered entities~~, whichever is less,~~ of a planned outage of telemetering equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

TOP-001-3

R10		N/A	~~N/A~~ The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.2.	~~N/A~~ The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities. ~~identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area~~

TOP-001-3: Requirement R13 Severe VSL - The Transmission Operator did not perform Real-time Assessments. OR, ~~-~~For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for ~~three~~four or more 30-minute periods within that 24-hour period.

TOP-002-4

R3	The Transmission Operator did not notify one impacted entity or 5% or less of the impacted entities, whichever is less identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted ~~NERC~~entities or more than 10% and less than or equal to 15% of the impacted entities, whichever is less, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more impacted ~~NERC~~entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two ~~impacted~~ entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more ~~impacted~~ entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).

TOP-003-3:

R5	~~N/A~~ The responsible entity receiving a data specification in	The responsible entity receiving a data specification in	The responsible entity receiving a data specification in	~~The responsible entity receiving a data specification in~~

	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~one~~two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~two~~three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	~~Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).~~ ~~OR,~~ The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

Organization	Yes or No	Question 11 Comments
City of Austin	No	The VSL for TOP-003-3, R5 should parallel the VSL for IRO-010-2, R3. That is, the moderate level should be lower, the high should be moderate and the first half of severe should be high.
Response: The SDT agrees as the VSLs for proposed TOP-003-3 and proposed IRO-010-2 should agree and the VSLs for proposed IRO-010-2 are based on VSLs for approved IRO-010-1. See summary for wording.		

Organization	Yes or No	Question 11 Comments
Texas Reliability Entity	No	1) IRO-008-2, Requirement R4 VSLs - Suggest the SDT remove “NERC registered” to be consistent with the Requirement R4 language and other standards in this project. The words were removed once in the VSLs but they occur twice in the VSLs. 2) IRO-008-2, Requirement R6 VSL - Texas RE requests the SDT consider revising the R6 VSL to contain only a Severe VSL. Texas RE submits that any failure to notify of IROL or SOL exceedances could result in cascading outages. 3) TOP-001-3, Requirements R8 and R9 VSLs - Texas RE recommends removing each instance of the phrase “whichever is less” from the R8 and R9 VSLs or at least from the Severe VSLs. At worst, it appears to nullify intent stated by the SDT for R8 and R9 that a situation where a small entity did not inform just one affected entity should be a Severe violation. At best, it adds no clarity to assessing violation severity levels. Specifically, for R8, if a small TOP with 1 known impacted other TOP did not notify that impacted TOP then it’s 100% which should make it a Severe VSL. However, the phrase “whichever is less” appears to kick it back to a Lower VSL because it is only one failure to inform, not four or more, which is less. It’s important to note that TOP-002-4, Requirements R3 and R5 do not include the phrase “whichever is less” in the Severe VSL language which is presumably a recognition that it doesn’t apply in the Severe VSL. 4) TOP-002-4, Requirements R3 and R5 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R3 and R5 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs. 5) TOP-003-3, Requirements R3 and R4 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R3 and R4 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs.

Organization	Yes or No	Question 11 Comments
		6) IRO-010-2, Requirement R2 - Texas RE recommends removing each instance of the phrase “whichever is less” from the R2 VSLs. The phrase adds no clarity to assessing violation severity levels; in fact it is likely to add confusion to the determination of VSLs. TOP-001-3: Requirement R9, M9 and R9 VSL: Suggest the SDT remove “NERC registered” to be consistent with other standards in this project.
Response: 1) The SDT believes that the comment refers to Requirement R3 VSLs. The SDT agrees and has deleted the phrase ‘NERC registered’ from all VSLs for Requirement R3. 2) The SDT disagrees and believes that an incremental approach is the correct one for reliability. No change made. 3) The SDT agrees and has deleted the phrase ’whichever is less’ from the Severe VSL only for both Requirement R8 and R9. 4) The SDT disagrees but has made grammatical corrections to the VSLs which it believes may have led to confusion. 5) The SDT disagrees and believes that the wording is correct. No change made. 6) The SDT disagrees and believes that the wording is correct. No change made.		
Duke Energy	No	Duke Energy does not necessarily disagree with the VRF(s) for IRO-017. However, we are seeking clarification for the increases in VRF from a “lower” in the first posting to a “medium” on this posting.
PacifiCorp	No	PacifiCorp cannot support the proposed change of the Violation Risk Factor in IRO-017-1 R3 from Low to Medium with inadequate justification for the change.
Response: As was pointed out in the VRF/VSL Justification document for the second posting, the Medium VRFs are because of the need to correspond to similar requirement VRFs for consistency as per the VRF Guidelines. Similar requirements had Medium VRFs so proposed IRO-017-1 was assigned Medium VRFs.		

Organization	Yes or No	Question 11 Comments
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	No	IRO-008-2R4 - Change the Severe VSL for new Requirement R4 (old R5) to read '...more than three...' or '...four or more...' in lieu of '...three or more...'. The High VSL already uses three. IRO-014-3R3 - The lead-in for the VSLs for Requirement R3 refers to Requirement R5. This reference should be to Requirement R3. R7 - Change the Severe VSL for Requirement R7 to read '...Coordinator had implemented...' and '...or would have violated safety...'. IRO-017-1R2 - Make Reliability Coordinator possessive in the Severe VSL for Requirement R2. TOP-001-3R8 - Delete 'other' in the VSLs for Requirement R8 referring to '...other known impacted Balancing Authorities...' and '...other Balancing Authorities...'. The use of 'other' only applies to references to Transmission Operator. Also in the VSLs for R8, change 'less' to 'greater' such that the Lower VSL would read: 'The Transmission Operator did not inform one other known impacted Transmission Operator or 5% or less of the affected known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.' (This particular change applies to all VSLs in R8, R9, R19 and R20 as well as the VSLs for IRO-002-4, R1; IRO-008-2, R3, R5, R6; IRO-010-2, R2; TOP-002-4, R3, R5; TOP-003-3, R3, R4.) R9 - Delete the term 'NERC registered' in the VSLs for Requirement R9. (See comment in Question 7 above. R13 - Change the Severe VSL for Requirement R13 to read '...more than three...' or '...four or more...' in lieu of '...three or more...'. The High VSL already uses three.

Organization	Yes or No	Question 11 Comments
		R19/R20 - Replace 'applicable' with 'identified' in the VSLs for Requirements R19 and R20. The use of 'identified' parallels the language in the requirements. TOP-002-4R3 - Replace 'NERC' with 'entities' in the High and Severe VSLs for Requirement R3.
Response: Proposed IRO-008-2 Requirement R4 VSL does not use the 'three or more' language cited. No change made. IRO-014-3 Requirement R3: The SDT agrees and has corrected the typo. IRO-014-3 Requirement R7: The SDT agrees and has made the suggested change. See summary for wording. IRO-017-1 Requirement R2: The SDT agrees and has made the suggested change. See summary for wording. TOP-001-3 Requirement R8: The SDT agrees and has deleted 'other' as suggested. See summary for wording of Severe VSL. TOP-001-3 Requirement R8: The SDT agrees with the change of 'lesser' to 'greater' in this standard and all others cited. Due to the simple replacement of one word and the volume of changes, the actual changes are only shown in the redlined standards. TOP-001-3 Requirement R9: The SDT agrees and has deleted the term 'NERC registered'. Due to the simple deletion of the phrase, the actual changes are only shown in the redlined standards. TOP-001-3 Requirement R13: The SDT agrees and has made the suggested change. See summary for wording. TOP-001-3 Requirement R19 and R20: The SDT agrees and has made the suggested change. Due to the simple replacement of one word, the actual changes are only shown in the redlined standards. TOP-002-4 Requirement R3: The SDT agrees and has made the suggested change. See summary for wording.		
Tennessee Valley Authority	No	TOP-001-3. There should be more than one level of VSL. As currently written there seems to be no allowance for instances where entities may be operating at two different ratings (i.e. temperature-dependent ratings, directional ratings, etc.) or a period of time before the entities coordinate which rating should be used in real-time.

Organization	Yes or No	Question 11 Comments
Response: The VSL for this requirement is based on a similar requirement and VSL for approved IRO-009-1 Requirement R5. That VSL is binary Severe. The SDT is supposed to structure VSLs whenever possible from existing approved VSLs. Therefore, the SDT assigned a binary Severe VSL to this requirement. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern disagrees that any violation of IRO-001-4 requirements constitutes a Severe VSL. The RSAW suggests that auditors are to use the NERC EAP process (i.e. reviewing entity's Category 2 or higher events) in their compliance assessment. Southern agrees with this approach and suggest the SDT adopt this thought process in the VSLs. For example, a Severe VSL would be a case where there was non-compliance for a Category 4 or 5 event, a High VSL would be for Category 3 events, and so on. This method should be used as not all events where Operating Instructions are issued, are equal.
Response: The VSLs for these requirements are based on similar requirements and VSLs for approved IRO-001-1.1. Those VSLs are binary Severe. The SDT is supposed to structure VSLs whenever possible from existing approved VSLs. Therefore, the SDT assigned a binary Severe VSL to these requirements. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	TOP-001-3 R2 Severe VSL - Remove "within its Transmission Operator Area" to maintain consistency with current R2. TOP-001-3 R7 Severe VSL - Replace "if requested" with "when requested" and "when the requesting" with "and the requested" to avoid issues with predicting future performance, and correct possession of the requested entity. Suggested language: "The Transmission Operator did not provide assistance to other Transmission Operators, when requested and able and the requested entity had implemented its emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements."

Organization	Yes or No	Question 11 Comments
Response: The SDT assumes that the commenter is referring to Requirement R1. The SDT has made changes to the requirement language which is reflected in the VSL language. See summary for wording. The SDT agrees and has made the suggested changes. See summary for wording.		
Hydro Quebec	No	TOP-001-3: Table of Compliance Elements: VSLs for R8 and R9 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. Example: "Violation Severity Levels for requirement 8 are determined based on the number of other known impacted Transmission Operators or other known impacted Balancing Authorities that the Responsible Entity did not inform of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas or Balancing Authority Areas when conditions did permit such communications :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" The whole wording of the requirement could be omitted for more clarity :"Violation Severity Levels for requirement 8 are determined based on the number of other known impacted entities that the Responsible Entity did not inform in accordance with that requirement :High VSL : The lesser of 1) three other known impacted Transmission Operators or 2) 10% or more but less than or equal to 15% of the other known impacted Transmission Operators OR The lesser of 1) three other known impacted Balancing Authorities or 2) 10% or more but less than or equal to 15% of the other known impacted Balancing Authorities" IRO-008: Table of Compliance Elements: VSLs for R4, R6 and R8 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.

Organization	Yes or No	Question 11 Comments
		IRO-010: Table of Compliance Elements: VSLs for R2 should be reworded. Due to their importance in determining penalties, VSL should be written clearly and without ambiguity. See examples given for TOP-001-3.
Response: The language cited by the commenter as an 'introduction' to the Requirement R8 and R9 VSLs has been used previously in other standards and is an acceptable method. The SDT has made changes to the language of the VSLs based on other comments but believes that the remaining language is clear as written. The re-worded Severe VSLs are shown in the summary. There is no Requirement R8 for proposed IRO-008-2. The SDT has made changes to the language of the VSLs in proposed IRO-008-2 based on other comments but believes that the remaining language is clear as written. See the redlined standard for the complete list of changes. The language cited by the commenter as an 'introduction' to the Requirement R2 VSLs has been used previously in other standards and is an acceptable method. The SDT has made changes to the language of the VSLs based on other comments but believes that the remaining language is clear as written. See the redlined standard for a complete list of changes.		
ERCOT	No	IRO-008: ERCOT suggests that the SDT review the language of Requirement R5 and its VSL for consistency. In particular, Requirement R5 was modified to require that the Reliability Coordinator ensure that a Real-Time Assessment is performed every 30 minutes. However, the VSL still assesses the condition that the Reliability Coordinator did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. These should be reviewed and revised to ensure consistency between the requirement and its VSL. IRO-008: ERCOT has identified a potential typographical error in R6 and all of its VSLs. Specifically, the reference to "as identified in identified in Requirement R6" should likely be reviewed and revised to "as identified in Requirement R5". IRO-008: ERCOT respectfully reiterates its previous comment on the inconsistent language used between Requirements R5 and R6 and the LOWER VSL for Requirement R8. In particular, the word "Emergency" is used in the VSL for Requirement R8 but the condition is not specified elsewhere in the standard or the appropriate referenced requirements. Please revise the lower VSL for

Organization	Yes or No	Question 11 Comments
		Requirement R8 to ensure consistency. The following language is proposed: "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated". IRO-014: ERCOT respectfully recommends that, for consistency, the VSLs for Requirement R2 be modified to remove references to criteria and state that Reliability Coordinator failed to maintain Operating Plans, Processes, or Procedures pursuant to one part of Parts 2.1 - 2.3, two parts of Parts 2.1 - 2.3, and so on.
Response: The SDT assumes the commenter is referring to Requirement R4 and agrees and has made changes to the Severe VSL. See summary for wording. The SDT agrees and has corrected the typographical error. The SDT assumes the commenter was referring to Requirement R6 Lower VSL as there is no Requirement R8. The SDT agrees and has corrected the typographical error. The SDT agrees and has made the suggested changes. See summary for wording.		
IRC Standards Review Committee Independent Electricity System Operator	No	IRO-008: R6 and all of its VSL: The reference to "as identified in identified in Requirement R6" should be revised to "as identified in identified in Requirement R5". IRO-008: We wish to reiterate our previous comment on the inconsistent language used between Requirement R6 (was R8 but misquoted in our previous comment as R6) and the LOWER VSL for R6 in which the word "Emergency" is used but the condition is not specified in R6.R6 stipulates that: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 has been prevented or mitigated. However, the LOWER VSL for R6 indicates that: The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan "when the Emergency

Organization	Yes or No	Question 11 Comments
		identified in Requirement R6 was prevented or mitigated." Please revise VSL to read "when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated" as opposed to "Emergency" for consistency. IRO-008: The language between R4 and its VSL is inconsistent.R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. This requirement was changed from having the RC to "perform" to "ensure that" a Real-time Assessment is performed. However, the VSL still assesses the condition that the RC did not "perform" as opposed to did not "ensure that" the Real-time Assessment was performed. Please revise as appropriate.
Response: The SDT agrees and has corrected the typographical error. The SDT agrees and has corrected the typographical error. The SDT agrees and has changed the VSL language. See summary for wording.		
Peak Reliability	Yes	TOP-001-3 R13: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted ...3 times....Severe VSL TO RTA not conducted 3 or more times...) IRO-008-2 R4: The VSL removed the first occurrence of the term "NERC registered" entity but left the term in the second half of the VSL. IRO-008-2 R5: The High VSL and Severe VSL overlap (High VSL TO RTA not conducted ...3 times....Severe VSL TO RTA not conducted 3 or more times...)
Response: The SDT agrees and has revised the Severe VSL. See summary for wording. The SDT assumes that the commenter is referring to Requirement R3 and agrees and has made the suggested change. See summary for wording. The SDT assumes the commenter is referring to Requirement R4 and agrees and has made the suggested change. See summary for wording.		

Organization	Yes or No	Question 11 Comments
Northeast Power Coordinating Council Hydro One	Yes	
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Clark Public Utilities	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc.	Yes	
Northern Indiana Public Service Company (NIPSCO)	Yes	
Independent Electricity System Operator	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Yes or No	Question 11 Comments
Salt River Project	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery LLC	Yes	
ReliabilityFirst	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Northeast Utilities	Yes	
MidAmerican Energy Company	Yes	
Response: Thank you for your support.		

12. **Are there any other concerns with these standards that haven't been covered in previous questions and comments?**

Summary Consideration: The SDT has not made any additional changes to the standards based on comments to this question.

Organization	Yes or No	Question 12 Comments
Dominion Compliance Policy	Yes	Dominion encourages the SDT to continue to monitor the status of the proposed definition of Remedial Action Scheme "RAS" as the change in definition will impact this reliability standard as well as other related standards as identified in NERC's white paper, Uses of "Special Protection System" and "Remedial Action Scheme" in Reliability Standards.
Response: Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term then a project will be undertaken to make the necessary corrections throughout all standards. No change made.		
Texas Reliability Entity	Yes	1) Texas RE appreciates the work that the SDT has done to address the comments received from industry during the previous ballot and comment period. Thank you for the time you have put into working towards making a set of steady state TOP and IRO standards. 2) Texas RE has one general comment regarding data retention for all the standards within this project. Texas RE recommends the SDT consider aligning the retention periods with the Data Retention and Sampling Team (DRAST) white paper which indicates a 4-year retention period for data with limited exemptions, such as a 6-month rolling period for high volume data, and 90-days for voice and audio recordings. 3) Operational Planning Analysis definition: Texas RE requests the SDT provide explanation for why the phrase "may be performed either a day ahead or as much as 12 months ahead" was removed from the proposed definition. The phrase is included in the current Glossary defined term. Following up on our comment from the

Organization	Yes or No	Question 12 Comments
		previous ballot and comment period, Texas RE still asserts that without that phrase the time frame for one day up to 12 months is not accounted for.
Response: Thank you for your support. The SDT has reviewed the data retention periods and believes that they are correct as stated. No change made. The SDT believed the parenthetical was not required as part of the definition. The Operations Planning Time Horizon includes conditions seen in studies, from day-ahead up to and including seasonal (which the SDT has stated that it believes essentially equates to one year), that may impact the Real-time reliability of the Reliability Coordinator Area. No change made.		
FRCC Compliance	Yes	1. IRO-001-4 R1, TOP-001-3 R1 & R3: The phrase "... to ensure the reliability of its RC/TOP/BA Area." is not measurable. The requirements should be stated so that the stated reliability is objectively measurable. For example, "... to ensure all Facilities within the RC/TOP/BA Area remain within SOLs and IROLs." Otherwise, the requirements are too vague as to when the RC/TOP/BA would be required to act, or whether the action taken was sufficient to ensure reliability. 2. TOP-002-4 R1: The definition of Operational Planning Analysis does not specify what "potential (post-Contingency) conditions" are to be evaluated, and is therefore not measurable. Either the requirement or the definition should be revised to clarify and add measurability as to which contingencies are required to be included in the analysis. 3. TOP-002-4 R4 (4.2): The phrase "...for the next-day that addresses: Interchange scheduling" is too vague and not measurable. The requirement should be stated so as to be objectively measurable. For example, "... for the next-day that addresses: Expected Interchange scheduling". 4. TOP-002-4 R4 (4.4): The phrase "... for the next-day that addresses: Capacity and energy reserve requirements ..." is not measurable. Applicable reserve requirements should be clearly provided to provide measurability as to whether the Operating Plan

Organization	Yes or No	Question 12 Comments
		addressed them. For example, "... for the next-day that addresses: Capacity and energy reserve requirements (at a minimum N-1 Contingency planning) ..."
Response: 1. The SDT has revised the requirement to delete 'ensure' and replace it with 'address' as in the first posting. 2. The purpose of proposed TOP-002-4 Requirement R1 is to perform an Operational Planning Analysis to identify SOL exceedances. The SOL Exceedance White Paper provide additional clarity by pointing to other requirements within FAC, TOP and IRO standards, including examples. No change made. 3. The SDT believes "expected" is implied since the Operational Planning Analysis is targeting "next-day" system conditions. No change made. 4. The SDT chose to use the generic term "Capacity and Energy Reserve Requirements" as part of the Interconnection-wide standard and believes that it is measurable. Minimum Reserve Requirements are addressed as part of the BAL standard. Balancing Authorities may have differing reserve requirements based on system conditions that need to be communicated to their Transmission Operator and Reliability Coordinator. No change required.		
Puget Sound Energy	Yes	As discussed in the comments addressing IRO-017, requirements R1 and R2 of that proposed standard should be phased with requirement R1 becoming effective prior to R2. Just as in IRO-010, the BAs and TOPs subject to requirement R2 are likely to need some time to implement the processes specified in RC's outage coordination process. In addition, connecting the implementation time to COM-001-2 if this group of standards is approved prior to or concurrent with COM-001-2 and COM-002-4 could result in a short implementation time. For example, say that FERC approval of both the COM standards and the IRO/TOP standards becomes effective on June 30, 2015. According to the implementation plan, the standards will "become effective concurrently with COM-001-2 and the definition of Operating Instruction". The effective date of COM-001-2 is "first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities..." which would be October 1, 2015 in this example. There is some ambiguity with this result since the term Operating Instruction is not used in COM-001-2, but in any case, using the effective date of COM-002-4, which is more consistent with the implementation period of the IRO/TOP standards, seems more appropriate.

Organization	Yes or No	Question 12 Comments
Response: The SDT disagrees that a staggered approach is needed. These items are not going to be created in a vacuum and the SDT believes that the entities involved will be coordinating as the process is developed. No change made.		
Northeast Power Coordinating Council	Yes	Because of the similarities in Purposes, Applicability's, and Requirements of standards within the group that is posted, combining requirements with the intent on reducing the number of standards should be considered. During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. The SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid. In other word, there does not exist any "proven reliable power system limits" as stated in R4 of TOP-002-4. While the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon may seem appropriate, the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state. If R4 in TOP-004-2 is retired, it leaves a potential reliability gap. The white paper does not mandate the proper and necessary action to "restore operations to respect proven reliable power system limits within

Organization	Yes or No	Question 12 Comments
		30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. A proper Quality Review of the postings would have eliminated the necessity of submitting many of the above comments.
Response: The SDT has made every effort to consolidate topics to reduce the number of requirements and standards in this project. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_v. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. The SDT submitted the documents to Quality Review as required and received numerous comments and suggestions for changes/corrections that were accepted by the SDT.		
IRC Standards Review Committee Independent Electricity System Operator	Yes	During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. he SDT's response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing

Organization	Yes or No	Question 12 Comments
		and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any "proven reliable power system limits" as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a "white paper" status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary action to "restore operations to respect proven reliable power system limits within 30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. Please advise.

Organization	Yes or No	Question 12 Comments
Response: 1. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_v. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. 2. The SDT does not plan on balloting for the retirement of approved TOP-004-2 since the intent of the requirement was successfully mapped as part of the Mapping Document. Acceptance of the proposed standards which includes the Mapping Document is considered sufficient to retire the standards cited in the Implementation Plan. No change made.		
Northern Indiana Public Service Company (NIPSCO)	Yes	NIPSCO is voting against approving the definitions for the following reasons: 1. In the new definition of Operational Planning Analysis and Real-time Assessment, Facility Rating and equipment limitations are listed. NIPSCO feels these should be removed and SOL and IROL be added. SOL and IROL include but is not limited to Facility Ratings and equipment limitations. See our comments on TOP-002 for more information. 2. In the new definition of Operational Planning Analysis and Real-time Assessment, Phase Angle is listed as an included input. NIPSCO feels this needs more definition. Is this for every node?
Response: 1. The SDT recognizes the concern but believes the proposed TOP-001-3 Requirement R13, TOP-001-3 Requirement R14, TOP-002-4 Requirement R1 and TOP-002-4 Requirement R2 further define the purpose of the Real-time Assessment and Operational Planning Analysis is to address potential SOL exceedances. No change made.		

Organization	Yes or No	Question 12 Comments
2. The inclusion of phase angle is based on the Southwest Outage recommendations. The SDT felt it was more prudent to include this item as part of the definition as opposed to a specific requirement within the standard. SDT has incorporated "applicable" based on industry feedback and believes that the proposed definition reflects an entity's responsibility to model and assess the impacts of phase angles. For example, modeling and assessment of phase angle reclosing limitations would be supported by Operating Plans. An entity can only provide data and information on what it has available and the addition of the term 'applicable' was intended to capture that intent and to protect an entity against unreasonable expectations. No change made.		
Seattle City Light	Yes	SCL asks that the Implementation Plan be revised to conform with our recommendations that the implementation periods and effective dates for IRO-010-2 and TOP-003-3 be extended to eighteen and twenty-four months (to allow sufficient time to negotiate and implement data exchange agreements among entities), as indicated above.
Response: The SDT does not believe that additional implementation time is required. Data exchange agreements need not take significant time to negotiate. Data specified by the Reliability Coordinator must be supplied in order to preserve reliability. No change made.		
SPP Standards Review Group Kansas City Power & Light Colorado Springs Utilities	Yes	The definition of Special Protection System (SPS) is being revised to Remedial Action Scheme (RAS) yet this package of standards continues to use SPS. Other active drafting teams, particularly the Relay Loadability: Stable Power Swings and the Protective System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) teams, are using the new RAS definition in their work. What process will be used to make the transition to RAS when the new definition is approved? Similarly, Load-Serving Entity will soon be eliminated as a registered function at NERC. How will this change be reflected in the standards? We recommend that all changes we have proposed for the standards be reflected in the RSAWs as well.

Organization	Yes or No	Question 12 Comments
Response: Until Remedial Action Scheme has become the official approved definition, the SDT will use the existing language of Special Protection System. If Remedial Action Scheme is adopted as the new, official term then a project will be undertaken to make the necessary corrections throughout all standards. No change made. Changes to requirement language due to industry comments will be reflected in RSAWs.		
Electric Reliability Council of Texas, Inc.	Yes	1. The proposed definitions of Real-Time Assessment and Operational Planning Analysis require use of applicable inputs. ERCOT respectfully submits that many of these inputs can only be utilized once communicated by other entities. Accordingly, the following revision is proposed: Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable, known inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through contracted third-party services.) Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable, known inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through contracted third-party services.) 2. During the last posting, we expressed a concern over the proposed retirement of TOP-004-2, Requirement R4, which stipulates that:R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30

Organization	Yes or No	Question 12 Comments
		minutes. The SDT’s response to our comment indicates that: As presented in the white paper on the Treatment of SOLs, the proposed requirements are based on the concept of not depending on pre-determined existing SOLs/IROLs but rather to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. Those ratings and limits rarely change due to changes in system conditions, whereas predetermined SOLs and IROLs may change due to the assumptions they were based on. No change made. While we agree that the ratings and limits upon which the SOLs/IROLs are based rarely change due to changes in system conditions, the changes in system condition themselves can render any SOLs/IROLs invalid, especially those that are voltage or stability limits. In other word, there does not exist any “proven reliable power system limits” as stated in R4 of TOP-002-4. We generally support the concept of not depending on pre-determined existing SOLs/IROLs but rather, to monitor the existing and potential operating conditions and evaluate them against the same ratings and limits that SOLs/IROLs would be based upon. However the concept itself (and being in a “white paper” status), or use of any information in the white paper, does not help or mandate re-calculation of valid SOLs and IROLs when entering an unknown state, and the ratings and limits that do not change have no bearing on those SOLs/IROLs that are voltage or stability limited and which are more dependent on system conditions, which have changed. While R13 in TOP-001- 3 requires a TOP to ensure that a Real-time Assessment is performed at least once every 30 minutes, it falls short of specifying the expected outcome (or objectives), such as new/revised SOLs/IROLs and assessing system performance against the new limits. The proposed definition of Real-time Assessment is also short of specifying the development or calculation of SOLs/IROLs. Hence, between R13 of TOP-003-1 and the definition of RTA, there is a gap that in an unknown state/condition, a TOP is not required to (and hence will not) develop SOLs/IROLs that are valid for the prevailing conditions. Hence, if R4 in TOP-004-2 is retired, it will leave a reliability gap. The white paper does not mandate the proper and necessary

Organization	Yes or No	Question 12 Comments
		action to "restore operations to respect proven reliable power system limits within 30 minutes" when entering into an unknown state. We again urge the SDT to consider not retiring Requirement R4 of TOP-002-4. Finally, we are unclear whether or not the proposed retirement of TOP-004-2 will be balloted separately, which it should. 3. TOP-006 R6 is not captured accurately. If the BAL-005 standard is intended to address metering outside of generation resources and the equipment that ties it to the BES, then the TO/TOP should be added to the BAL-005 R17 requirement. ERCOT suggests creating a requirement that addresses accuracy, range, and sampling rate holistically and apply it to Transmission Owners and Generation Owners as they typically purchase and maintain such devices. ERCOT does not agree that TOP-004 R6.2 is addressed sufficiently in TOP-001-3 R8. ERCOT believes that all switching that could impact another Transmission Operator should be coordinated, and not a subset which R8 limits it to. Failure to coordinate by the Transmission Operators that have local or direct control could result in inadvertent loss of load. ERCOT does not agree with the justification utilized for TOP-002 R19. Planning models may differ from Operations models due to software variances, new / retired facilities timelines, seasonal variations, etc. Therefore MOD-033-1 does not address R19.

Response: 1. The SDT recognizes that only known inputs can be included as part of an RTA or OPA once the required information is communicated by other entities. No change made.

2. The SDT has discussed the concern over the retirement of approved TOP-004-2 Requirement R4 and believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL T_V. The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13. Both of these

Organization	Yes or No	Question 12 Comments
functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance. The event takes place and is analyzed against the set of limits currently in place. It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14. Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. 3. The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. The mapping document has been updated accordingly. 4. The SDT disagrees and believes that the proposed replacement addresses the situation. No change made. 5. Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. The SDT updated the mapping document.		
PacifiCorp	No	TOP-001-3 exceeds the NOPR by requiring Protection Systems in addition to Special Protection Systems. The tools used to produce Real-time Assessments using Real-time data are not dynamic stability assessment tools, and do not inherently understand the status of all "Protection Systems", degradations, or identified phase angles and equipment limitations. Note the definition references "Protection System and Special Protection System status," while the NOPR references only Special Protection Schemes.
Response: The SDT was required to consider additional inputs beyond the FERC NOPR as part of the Standards Development process. The SDT recognizes that not all Real-time Assessment tools include dynamic Stability assessments. Typically facilities with degraded protection systems are switched out-of-service. If the facilities are not switched out-of-service, Contingencies within the		

Organization	Yes or No	Question 12 Comments
Real-time Assessment should be modified to reflect remote clearing. If there are transient Stability concerns, Operating Plans would address expected operator actions. No change made.		
FRCC Operating Committee (Member Services) City of Tallahassee	Yes	The comments provided herein are consensus comments of the FRCC Operating Committee entity representatives. Our responses to the above questions in no way intends to convey how individual FRCC OC member entities will vote on the standards being proposed. Thank you for your efforts.
Florida Municipal Power Agency	No	FMPA appreciates the good work of the SDT in streamlining and improving the clarity of these standards.
PJM Interconnection	No	PJM is submitting affirmative ballots for all the standards. The revisions made to IRO-002-4 and IRO-008-2 addressed PJM's concerns with the previous drafts of these standards.
Associated Electric Cooperative, Inc. - JRO00088	No	
MRO NERC Standards Review Forum	No	
ACES Standards Collaborators	No	
Duke Energy	No	
Bonneville Power Administration	No	
Arizona Public Service Company	No	

Organization	Yes or No	Question 12 Comments
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Peak Reliability	No	
Clark Public Utilities	No	
American Electric Power	No	
South Carolina Electric and Gas	No	
CenterPoint Energy Houston Electric LLC	No	
Manitoba Hydro	No	
Pepco Holdings Inc.	No	
Idaho Power Company	No	
American Transmission Company, LLC	No	

Organization	Yes or No	Question 12 Comments
Xcel Energy	No	
Salt River Project	No	
Consumers Energy Company	No	
Oncor Electric Delivery LLC	No	
ReliabilityFirst	No	
Tennessee Valley Authority	No	
New York Independent System Operator (NYISO)	No	
Ameren	No	
Tri-State Generation and Transmission Association, Inc.	No	
Hydro One	No	
Northeast Utilities	No	
Georgia Transmission Corporation	No	
CPS Energy	No	
Indiana Municipal Power Agency	No	

Organization	Yes or No	Question 12 Comments
MidAmerican Energy Company	No	
Response: Thank you for your support.		

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 – March 24, 2014

First posting May 19, 2014 - July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes "Distribution Provider" to "Transmission Service provider"	Errata
1.1	October 29, 2008	Removed "proposed" from effective date BOT adopted errata changes: updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approval	Revised
2	July 25, 2011	Revisions under Project 2006-06 to remove Requirement R7 to avoid duplication with IRO-014-2	Revised
3	July 6, 2012	Revisions to complete scope of revisions under Project 2006-06	Revised
3	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions as per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose**: To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**

> **Rationale:** Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5.

4.1. Reliability Coordinator

4.2. Transmission Operator

4.3. Balancing Authority

4.4. Generator Operator

4.5. Distribution Provider

5. **Effective Date:**

See Implementation Plan.

6. **Background:**

See the Project 2014-03 project page.

B. Requirements and Measures

> **Rationale**: The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Rationale for Requirements R2 and R3: The Transmission Service Provider has been removed from Requirements R2 and R3 as the Transmission Service Provider is not listed in the Functional Model as a recipient of corrective actions issued by the Reliability Coordinator. This allows for the retirement of IRO-004-2.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with the Reliability Coordinator's Operating Instructions, and compliance with the Operating Instructions could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1 .

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

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Development Steps Completed

SAR posted for comment February 21, 2014 – March 24, 2014

First posting May 19, 2014 - July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	November 19, 2006	Changes "Distribution Provider" to "Transmission Service provider"	Errata
1.1	October 29, 2008	Removed "proposed" from effective date BOT adopted errata changes: updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approval	Revised
2	July 25, 2011	Revisions under Project 2006-06 to remove Requirement R7 to avoid duplication with IRO-014-2	Revised
3	July 6, 2012	Revisions to complete scope of revisions under Project 2006-06	Revised
3	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions as per Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title**: Reliability Coordination – Responsibilities
2. **Number**: IRO-001-4
3. **Purpose**: To establish the responsibility of Reliability Coordinators to act or direct other entities to act.
4. **Applicability**

> **Rationale:** Purchasing-Selling Entity and Load-Serving Entity have been deleted from the approved IRO-001-1.1 as they are not listed as entities that the Reliability Coordinator directs in Functional Model v5.

4.1. Reliability Coordinator

4.2. Transmission Operator

4.3. Balancing Authority

4.4. Generator Operator

4.5. Distribution Provider

5. **Effective Date:**

~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

See Implementation Plan.

6. **Background:**

See the Project 2014-03 project page.

B. Requirements and Measures

Rationale: The change from Reliability Directive to Operating Instruction throughout the standard is in response to NOPR paragraph 64 (…"*We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements). For example, mandatory compliance with directives in non-emergency situations is important when a decision is made to alter or maintain the state of an element on the interconnected transmission network…*") This change is also consistent with the proposed COM-002-4.

R1. Each Reliability Coordinator shall act~~, or direct others to act, by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted~~, or directed others to act, by issuing Operating Instructions~~ to ~~ensure~~address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Rationale for Requirements R2 and R3: The ~~addition of~~ Transmission Service Provider ~~to~~has been removed from Requirements R2 and R3 as the Transmission Service Provider is not listed in the Functional Model as a recipient of corrective actions issued by the Reliability Coordinator. This allows for the retirement of IRO-004-2.

R2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-time Operations]*

M2. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instructions, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instructions. If such a situation has not occurred, the Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ or Distribution Provider may provide an attestation.

R3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-time Operations]*

M3. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it informed its Reliability Coordinator of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, ~~Transmission Service Provider,~~ and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirement R1, Measure M1 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.
- The Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider for Requirements R2 and R3, Measures M2 and M3 shall retain voice recordings for the most recent 90-calendar days and documentation for the most recent 12-calendar months.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning,~~ Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to act~~, or direct others to act, by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R2	~~Operations Planning,~~ Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with the Reliability Coordinator's Operating Instructions, and compliance with the Operating Instructions could have been physically implemented and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R3	~~Operations Planning,~~ Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity failed to inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction issued by its Reliability Coordinator in Requirement R1 .

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Deleted R2, M3 and associated compliance elements Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	
4	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-4
3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Reliability Coordinator
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See the Project 2014-03 project page.

B. Requirements and Measures

Rationale: The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issue. Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R2. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Rationale: Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Rationale for Requirement R4: Requirement R4 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

R4. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M4. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R3 and Measures M1, M2, and M3.

The Reliability Coordinator shall keep data or evidence for Requirement R4 and Measure M4 for the current calendar year and one previous calendar year.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R3	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Operating Limit exceedances within its Reliability Coordinator Area.
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

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3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	
4	TBD	Revisions under Project 2014-03	Revised

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Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-4
3. **Purpose:** Provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability**

   4.1. Reliability Coordinator

5. **Effective Date:**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.

6. **Background:**

   See the Project 2014-03 project page.

B. Requirements and Measures

Rationale: The data exchange elements of Requirements R1 and R2 from approved IRO-002-2 have been added back into proposed IRO-002-4 in order to ensure that there is no reliability gap. The SDT found no proposed requirements in the current project that covered the issue~~s~~. ~~The currently-effective requirement in IRO-002-2 has been separated into two parts (Requirements R1 and R2 below) to distinguish voice and data requirements.~~ Voice communication is covered in proposed COM-001-2 but data communications needs to remain in IRO-002-4 as it is not covered in proposed COM-001-2. Staffing of communications and facilities in corresponding requirements from IRO-002-2 is addressed in approved PER-004-2, Requirement R1 and has been deleted from this draft.

R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M1. Each Reliability Coordinator shall have and provide upon request, evidence that could include but is not limited to a document that lists its data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its operational Planning Analyses, Real-time monitoring, and ~~r~~Real-time Assessments.

R2. Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has provided its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Rationale: Requirement R2 from IRO-002-3 has been deleted because approved EOP-008-1, Requirement R1, part 1.6.2 addresses redundancy and back-up concerns for outages of analysis tools. New Requirement R4 has been added to address NOPR paragraphs 96 and 97: *"…As we explain above, the reliability coordinator's obligation to monitor SOLs is important to reliability because a SOL can evolve into an IROL during deteriorating system conditions, and for potential system conditions such as this, the reliability coordinator's monitoring of SOLs provides a necessary backup function to the transmission operator…."*

R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitored Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability

Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Rationale for Requirement R4: Requirement R4 added back from approved IRO-002-2 as the SDT found no proposed requirements that covered the issues.

R4. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M4. The Reliability Coordinator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it has monitoring systems consistent with the requirement.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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The Reliability Coordinator shall keep data or evidence for Requirement R4 and Measure M4 for the current calendar year and one previous calendar year.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not have data exchange capabilities with one applicable entity, or 5% or less of the applicable entities, whichever is ~~less~~greater.	The Reliability Coordinator did not have data exchange capabilities with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is ~~less~~greater.	The Reliability Coordinator did not have data exchange capabilities with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is ~~less~~greater.	The Reliability Coordinator did not have data exchange capabilities with four or more applicable entities or greater than 15% of the applicable entities, whichever is ~~less~~greater.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.
R3	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval.	
2	April 2014	Revisions pursuant to Project 2014-03	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

Rationale for Applicability changes: Changes were made to applicability based on IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.

The Interchange Authority was removed because activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.

The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard.

4. **Applicability**
   - **4.1.** Reliability Coordinator.
   - **4.2.** Balancing Authority.
   - **4.3.** Generator Owner.
   - **4.4.** Generator Operator.
   - **4.5.** Load-Serving Entity.
   - **4.6.** Transmission Operator.
   - **4.7.** Transmission Owner.
   - **4.8.** Distribution Provider.

5. **Proposed Effective Date:**

   See Implementation Plan.

6. **Background**

   See Project 2014-03 project page.

B. Requirements

Rationale:

Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining non-BES and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

<table>
<tr><th rowspan="2">R#</th><th rowspan="2">Time Horizon</th><th rowspan="2">VRF</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower</th><th>Moderate</th><th>High</th><th>Severe</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td>monitoring, and Real-time Assessments.</td></tr>
<tr><td colspan="7">For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.</td></tr>
<tr><td>R2</td><td>Operations Planning</td><td>Low</td><td>The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator’s Operational Planning Analyses, and Real-time monitoring, and Real-time</td><td>The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time</td><td>The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time</td></tr>
</table>

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
				Assessments.	monitoring, and Real-time Assessments.	Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval.	
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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

> **Rationale for Applicability changes:** Changes were made to applicability based on IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.
>
> The Interchange Authority was removed because activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.
>
> The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard.

4. **Applicability**
   - **4.1.** Reliability Coordinator.
   - **4.2.** Balancing Authority.
   - **4.3.** Generator Owner.
   - **4.4.** Generator Operator.
   - **4.5.** Load-Serving Entity.
   - **4.6.** Transmission Operator.
   - **4.7.** Transmission Owner.
   - **4.8.** Distribution Provider.

5. **Proposed Effective Date:**

   ~~Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar~~

~~quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

See Implementation Plan.

6. Background

See Project 2014-03 project page.

B. Requirements

Rationale:

Proposed Requirement R1, Part 1.1 is in response to issues raised in NOPR paragraph 67 on the need for obtaining ~~sub-100 kV~~non-BES and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R3, Part 3.3 is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2 Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, ~~Planning Coordinator, Transmission Planner,~~ Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is ~~less~~greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is ~~less~~greater, that have data required by the Reliability Coordinator's	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is ~~less~~greater, that have data required by the Reliability	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is ~~less~~greater, that have data required by the Reliability Coordinator's Operational

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
			monitoring, and Real-time Assessments.	Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Definitions

Project 2014-03 Revisions to TOP/IRO Reliability Standards

As part of the work in Project 2014-03 Revisions to TOP/IRO Reliability Standards, the SDT is proposing changes to two existing definitions: Operational Planning Analysis and Real-time Assessment.

The currently-effective definition of Operational Planning Analysis is: *"An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)."*

The proposed version of the definition of Operational Planning Analysis is: *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*

The currently-effective definition of Real-time Assessment is: *"An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data."*

The proposed version of the definition of Real-time Assessment is: *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, TOP-003-3, IRO-002-4, IRO-008-2, and IRO-010-2. These definitions are not used in any other standards, either currently-effective or in development in any other project.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**
    - TOP-001-1a Reliability Responsibilities and Authorities
    - TOP-002—2.1b Normal Operations Planning
    - TOP-003-1 Planned Outage Coordination
    - TOP-004-2 Transmission Operations
    - TOP-005-2a Operational Reliability Information
    - TOP-006-2 Monitoring System Conditions
    - TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
    - TOP-008-1 Response to Transmission Limit Violations
    - IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
    - IRO-002-2 Reliability Coordination — Facilities
    - IRO-003-2 Reliability Coordination – Wide Area View
    - IRO-004-2 Reliability Coordination – Operations Planning
    - IRO-005-3.1a Reliability Coordination — Current Day Operations
    - IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
    - IRO-010-1a Reliability Coordinator Data Specification and Collection
    - IRO-014-1 Coordination Among Reliability Coordinators
    - IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
    - IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
    - PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project. Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:
   - TOP-001-2 Transmission Operations
   - TOP-002-3 Operations Planning
   - TOP-003-2 Operational Reliability Data
   - IRO-001-3 Reliability Coordination - Responsibilities and Authorities
   - IRO-002-3 Reliability Coordination — Analysis Tools
   - IRO-005-4 Reliability Coordination — Current Day Operations
   - IRO-014-2 Coordination Among Reliability Coordinators
   - PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the currently enforceable standards and definitions would remain effective until those approvals have occurred, and the new or revised standards in Project 2014-03 shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective three months earlier, in order to provide recipients of data requests from their Reliability Coordinators, Transmission Operators, and/or Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. **If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:**

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Final Ballots Now Open through October 20, 2014

Now Available

Final ballots and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for **TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1** are open through **8 p.m. Eastern on Monday, October 20, 2014**.

Additionally, final ballots for **IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan** are open through **8 p.m. Eastern on Monday, October 20, 2014**.

Instructions for Balloting
In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pools associated with this project may log in and submit their vote for the standards, definitions, implementation plan and associated VRFs and VSLs as described above by clicking here**.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Final Ballot and Non-Binding Poll Results

Now Available

Final ballots for **TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1** concluded at **8 p.m. Eastern, Monday, October 20, 2014**. The non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Wednesday, October 22, 2014**

Additionally, final ballots for **IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan** concluded at **8 p.m. Eastern, Monday, October 20, 2014.**

The standards achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results	Non-Binding Poll Results
	Quorum /Approval	Quorum/Supportive Opinions
IRO-001-4	90.77% / 82.64%	N/A
IRO-002-4	89.97% / 85.96%	N/A
IRO-008-2	89.71% / 83.73%	78.59% / 85.88%
IRO-010-2	89.97% / 86.22%	N/A
IRO-014-3	89.71% / 89.88%	78.59% / 91.33%
IRO-017-1	89.97% / 82.58%	78.89% / 92.18%
TOP-002-4	89.71% / 84.76%	78.89% / 86.77%
TOP-003-3	90.50% / 86.55%	78.30% / 82.29%
2 Definitions	88.39% / 94.07%	NA
Implementation Plan	88.39% / 91.84%	NA

Background information for this project can be found on the project page.

Next Steps

The standards and associated documents will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson,
Standards Developer, or by telephone at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-03 IRO-001-4
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	344
Total Ballot Pool:	379
Quorum:	**90.77 % The Quorum has been reached**
Weighted Segment Vote:	82.64 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	66	0.776	19	0.224	0	9	11
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	83	1	57	0.814	13	0.186	0	7	6
4 - Segment 4	30	1	20	0.833	4	0.167	0	2	4
5 - Segment 5	82	1	53	0.815	12	0.185	0	10	7
6 - Segment 6	52	1	35	0.795	9	0.205	0	4	4
7 - Segment 7	2	0	0	0	0	0	0	1	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**379**	**7.3**	**251**	**6.033**	**60**	**1.267**	**0**	**33**	**35**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Negative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	COMMENT RECEIVED
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	

1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS

1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	COMMENT RECEIVED
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	

3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	

4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	

5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	

6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	

10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-002-4
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	341
Total Ballot Pool:	379
Quorum:	**89.97 % The Quorum has been reached**
Weighted Segment Vote:	85.96 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	58	0.773	17	0.227	0	18	12
2 - Segment 2	9	0.7	6	0.6	1	0.1	0	1	1
3 - Segment 3	83	1	47	0.81	11	0.19	0	18	7
4 - Segment 4	30	1	15	0.882	2	0.118	0	10	3
5 - Segment 5	82	1	46	0.852	8	0.148	0	20	8
6 - Segment 6	52	1	31	0.886	4	0.114	0	12	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	1	0.1	1	0.1	0	1	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**379**	**7.1**	**216**	**6.103**	**44**	**0.997**	**0**	**81**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	

1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	

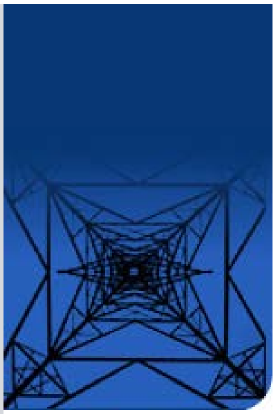
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD

				PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
				SUPPORTS

5	Duke Energy	Dale Q Goodwine	Negative	THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	

6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
	Commonwealth of Massachusetts Department			



9	of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Negative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2014-03 IRO-010-2
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	341
Total Ballot Pool:	379
Quorum:	**89.97 % The Quorum has been reached**
Weighted Segment Vote:	86.22 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	72	0.837	14	0.163	0	7	12
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	83	1	63	0.913	6	0.087	0	7	7
4 - Segment 4	30	1	22	0.957	1	0.043	0	4	3
5 - Segment 5	82	1	57	0.864	9	0.136	0	8	8
6 - Segment 6	52	1	40	0.909	4	0.091	0	3	5
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**379**	**7.4**	**273**	**6.38**	**39**	**1.02**	**0**	**29**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	

1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Affirmative	

1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD

				PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		

4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD

				PARTY COMMENTS
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	

6	Powerex Corp.	Gordon Dobson-Mack	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	NO COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2014-03 Definitions
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	335
Total Ballot Pool:	379
Quorum:	**88.39 % The Quorum has been reached**
Weighted Segment Vote:	94.07 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	72	0.911	7	0.089	0	12	14
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	1	2
3 - Segment 3	83	1	62	0.954	3	0.046	0	11	7
4 - Segment 4	30	1	19	1	0	0	0	7	4
5 - Segment 5	82	1	58	0.921	5	0.079	0	9	10
6 - Segment 6	52	1	38	0.905	4	0.095	0	5	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.6	6	0.6	0	0	0	2	0
Totals	**379**	**6.9**	**267**	**6.491**	**20**	**0.409**	**0**	**48**	**44**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	

1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	

3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	

3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		

5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	

6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Ballot Results	
Ballot Name:	Project 2014-03 TOP/IRO Implementation Plan
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	335
Total Ballot Pool:	379
Quorum:	**88.39 % The Quorum has been reached**
Weighted Segment Vote:	91.84 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	68	0.872	10	0.128	0	15	12
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	1	2
3 - Segment 3	83	1	58	0.921	5	0.079	0	13	7
4 - Segment 4	30	1	20	1	0	0	0	6	4
5 - Segment 5	82	1	51	0.864	8	0.136	0	12	11
6 - Segment 6	52	1	34	0.872	5	0.128	0	7	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.6	6	0.6	0	0	0	2	0
Totals	**379**	**7**	**250**	**6.429**	**29**	**0.571**	**0**	**56**	**44**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Abstain	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	

1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	

2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Abstain	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
	Boise-Kuna Irrigation District/dba Lucky peak			

5	power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
				SUPPORTS THIRD

5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	PARTY COMMENTS
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		

6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis.

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirement R2: The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

Rationale for Requirement R3: Changes in response to IERP recommendation.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Rationale for Requirements R4 and R5: These Requirements were added to address IERP recommendations.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or e-mail records.

Rationale for Requirements R6 and R7: Added in response to SW Outage Report recommendation 1.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not notify one impacted entity or 5% or less	The Balancing Authority did not notify two entities or more than 5% and	The Balancing Authority did not notify three impacted entities or	The Balancing Authority did not notify four or more entities or more than

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as identified in Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-4**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

5. **Effective Date:**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.

6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for Requirement R1: Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis.

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirement R2: The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

Rationale for Requirement R3: Changes in response to IERP recommendation.

R3. Each Transmission Operator shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

Rationale for Requirements R4 and R5: These Requirements were added to address IERP recommendations.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch

4.2 Interchange scheduling

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or e-mail records.

R5. Each Balancing Authority shall notify ~~impacted~~ entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified ~~impacted~~ entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or e-mail records.

Rationale for Requirements R6 and R7: Added in response to SW Outage Report recommendation 1.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next-day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90--calendar days period for analyses, the most recent 90--calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the ~~impacted~~ entities, whichever is ~~less~~greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two ~~impacted~~ entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted ~~NERC~~entities or more than 10% and less than or equal to 15% of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more ~~impacted~~ ~~NERC~~entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not	The Balancing Authority did not

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			notify one impacted entity or 5% or less of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	notify two ~~impacted~~ entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	notify three impacted entities or more than 10% and less than or equal to 15% of the ~~impacted~~ entities, whichever is ~~less~~greater, identified in the Operating Plan(s) as to their role in the plan(s).	notify four or more ~~impacted~~ entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next-day operations as identified in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Requirement R4 to its Reliability Coordinator.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operational Reliability Data**
2. **Number: TOP-003-3**
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.
4. **Applicability:**
   - **4.1.** Transmission Operator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Load-Serving Entity
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Changes to proposed Requirement R1, Part 1.1 are in response to issues raised in NOPR paragraph 67 on the need for obtaining non-BES and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data. The language has been moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability Coordinator.

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

Rationale for Requirement R5: Proposed Requirement R5, Part 5.3 is in **r**esponse to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Operational Reliability Data**
2. **Number: TOP-003-3**
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have data needed to fulfill their operational and planning responsibilities.
4. **Applicability:**
   - **4.1.** Transmission Operator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Load-Serving Entity
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:**

   ~~All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Changes to proposed Requirement R1, Part 1.1 are in response to issues raised in NOPR paragraph 67 on the need for obtaining ~~sub-100 kV~~non-BES and external network data necessary for the Transmission Operator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2 is in response to NOPR paragraph 78 on relay data. The language has been moved from approved PRC-001-1.

Corresponding changes have been made to Requirement R2 for the Balancing Authority and to proposed IRO-010-2, Requirement R1 for the Reliability Coordinator.

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including ~~sub-100 kV~~non-BES data and external network data as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data.

R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data.

R3. Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

Rationale for Requirement R5: Proposed Requirement R5, Part 5.3 is in **r**esponse to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

5.1. A mutually agreeable format

5.2. A mutually agreeable process for resolving data conflicts

5.3. A mutually agreeable security protocol

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Operations Planning	Low	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Low	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Low	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data	The Transmission Operator did not distribute its data

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specification to one entity, or 5% or less of the entities, whichever is ~~less~~greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is ~~less~~greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is ~~less~~greater, that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	specification to four or more entities, or more than 15% of the entities~~, whichever is less,~~ that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Low	The Balancing Authority did not distribute its data specification to one entity, or 5% or less of the entities, whichever is ~~less~~greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is ~~less~~greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is ~~less~~greater, that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its data specification to four or more entities, or more than 15% of the entities~~, whichever is less,~~ that have data required by the Balancing Authority's analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	~~N/A~~ The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet one of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~one~~two of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet ~~two~~three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).	~~The responsible entity receiving a data specification in Requirement R3 or R4 satisfied the obligations in the data specification but did not meet all three of the criteria shown in Requirement R5 (Parts 5.1 – 5.3).~~ ~~OR,~~ The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting from May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-2
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

> **Rationale for Requirement R1**: Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

> **Rationale for Requirements R2 and R3**: Requirements added in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and

Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirements R5 and R6: In Requirements R5 and R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30-calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

<table>
<tr><th rowspan="2">R#</th><th rowspan="2">Time Horizons</th><th rowspan="2">VRF</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td colspan="7">For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation</td></tr>
<tr><td>R3</td><td>Operations Planning</td><td>Medium</td><td>The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted entities whichever is greater identified in its Operating Plan(s) as to their role in that plan(s).</td><td>The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).</td><td>The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted entities whichever is greater, identified in its Operating Plan(s) as to their role in that plan(s).</td><td>The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted entities identified in its Operating Plan(s) as to their role in that plan(s).</td></tr>
<tr><td>R4</td><td>Same-day Operations, Real-time Operations</td><td>High</td><td>For any sample 24-hour period within the 30-day retention period, the Reliability</td><td>For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator’s</td><td>For any sample 24-hour period within the 30-day retention period, the Reliability</td><td>For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator’s Real-time Assessment was not conducted for three or more 30-minute periods</td></tr>
</table>

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) or Interconnection Reliability	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is greater, when the System Operating Limit	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in	(IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or	(SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit	

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Requirement R5 was prevented or mitigated.	mitigated.	(IROL) exceedance identified in Requirement R5 was prevented or mitigated.	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting from May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	
1	February 28, 2014	Updated VSLs and VRF's based on June 24, 2013 approval.	
2	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Real-time Assessment: An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis: An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

A. Introduction

1. **Title**: Reliability Coordinator Operational Analyses and Real-time Assessments
2. **Number:** IRO-008-2
3. **Purpose:** Perform analyses and assessments to prevent instability, uncontrolled separation, or Cascading.
4. **Applicability**

   4.1. Reliability Coordinator.
5. **Proposed Effective Date:**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale for Requirement R1: Revised in response to NOPR paragraph 96 on the obligation of Reliability Coordinators to monitor SOLs. Measure M1 revised for consistency with TOP-003-3, Measure M1.

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

Rationale for Requirements R2 and R3: Requirements added ~~I~~in response to IERP and SW Outage Report recommendations concerning the coordination and review of plans.

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Reliability Coordinator shall have evidence that it has a coordinated Operating Plan for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. Such evidence could include but is not limited to plans for precluding operating in excess of each SOL and IROL that were identified as a result of the Operational Planning Analysis.

R3. Each Reliability Coordinator shall notify impacted entities identified in its ~~the~~ Operating Plan(s) cited in Requirement R2 as to their role in ~~those~~ such plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have evidence that it notified impacted entities identified in its ~~the~~ Operating Plan(s) cited in Requirement R2 as to their role in ~~the~~ such plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirements R5 and R6: In Requirements R5 and R6 the use of the term 'impacted' and the tie to the Operating Plan where notification protocols will be set out should minimize the volume of notifications.

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~ Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, of its actual or expected operations that result in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

R6. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 has been prevented or mitigated. *[Violation Risk Factor: Medium] [Time Horizon: Same-Day Operations, Real-time Operations]*

M6. Each Reliability Coordinator shall make available upon request, evidence that it informed impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 has been prevented or mitigated. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Reliability Coordinator shall keep data or evidence to show compliance for Requirements R1 through R3, R5, and R6 and Measures M1 through M3, M5, and M6 for a rolling 90--calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Reliability Coordinator shall each keep data or evidence for Requirement R4 and Measure M4 for a rolling 30--calendar day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not perform an Operational Planning Analysis allowing it to assess whether its planned operations for the next-day within its Wide Area will exceed any of its System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Reliability Coordinator did not have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation						
R3	Operations Planning	Medium	The Reliability Coordinator did not notify one impacted entity or 5% or less of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify two impacted entities or more than 5% and less than or equal to 10% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify three impacted entities or more than 10% and less than or equal to 15% of the impacted ~~NERC registered~~ entities whichever is ~~less~~greater, identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).	The Reliability Coordinator did not notify four or more impacted entities or more than 15% of the impacted ~~NERC registered~~ entities identified in ~~the~~its Operating Plan(s) as to their role in ~~those~~that plan(s).
R4	Same-day Operations, Real-time	High	For any sample 24-hour period within the 30-	For any sample 24-hour period within the 30-day retention period,	For any sample 24-hour period within the 30-	~~The Reliability Coordinator did not perform Real-time Assessments.~~

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations		day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	the Reliability Coordinator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	~~OR~~ For any sample 24-hour period within the 30-day retention period, the Reliability Coordinator's Real-time Assessment was not conducted for three or more 30-minute periods within that 24-hour period.
R5	Same-Day Operations, Real-time Operations	High	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and	The Reliability Coordinator did not notify two impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission	The Reliability Coordinator did not notify three impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of	The Reliability Coordinator did not notify four or more impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area identified in the Operating Plan(s) as to their role in the plan(s). OR The Reliability Coordinator did not notify the other impacted

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Balancing Authorities within its Reliability Coordinator Area whichever is ~~less~~greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~	Operators and Balancing Authorities within its Reliability Coordinator Area whichever is ~~less~~greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~ Wide Area.	the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is ~~less~~greater, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance	Reliability Coordinators, as indicated in its Operating Plan, when the results of its Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its ~~Reliability Coordinator~~ Wide Area.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Wide Area.		within its ~~Reliability Coordinator~~ Wide Area.	
R6	Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one impacted Transmission Operator or Balancing Authority within its Reliability Coordinator Area or 5% or less of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is ~~less~~greater,	The Reliability Coordinator did not notify two impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 5% and less than or equal to 10% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area whichever is ~~less~~greater, when	The Reliability Coordinator did not notify three impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 10% and less than or equal to 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability	The Reliability Coordinator did not notify four or more impacted Transmission Operators or Balancing Authorities within its Reliability Coordinator Area or more than 15% of the impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated. OR The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated. OR The Reliability Coordinator did not notify one other impacted Reliability Coordinator as indicated in its Operating Plan when the ~~Emergency~~ when the	the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R6 was prevented or mitigated. OR The Reliability Coordinator did not notify two other impacted Reliability Coordinators as indicated in its Operating Plan when the System Operating Limit (SOL) or Interconnection Reliability	Coordinator Area whichever is ~~less~~greater, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated. OR The Reliability Coordinator did not notify three other impacted Reliability Coordinators as indicated in its Operating Plan	Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated.

R#	Time Horizons	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated.	Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated.	when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R~~6~~5 was prevented or mitigated.	

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06
2		Revised under Project 2006-06	Revised
2	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators
2. **Number:** IRO-014-3
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability:**
   4.1. Reliability Coordinator
5. **Effective Date**
   See Implementation Plan.
6. **Background:**
   See Project 2014-03 project page.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. Criteria and processes for notifications.

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. Provisions for periodic communications to support reliable operations.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that its Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

Rationale: Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.

R4. Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

R5. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator that identifies an Emergency in its Reliability Coordinator Area shall have evidence that it developed an action plan during those instances where impacted Reliability Coordinators disagreed on the existence of an Emergency. This evidence may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation.

R6. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each impacted Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who identifies the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

Rationale for Requirement R7: Language added for consistency with proposed TOP-001-3, Requirement R7.

R7. Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M7. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 and R2 and Measures M1 and M2.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement R5 and Measure M5.
- Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirement R6 and Measure M6.
- Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements R3, R4, and R7 and Measures M3, M4, and M7.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability. OR, The Reliability Coordinator failed to implement its Operating Procedures, Operating processes, or Operating Plans when activities required notification, or coordination of actions with impacted adjacent Reliability Coordinators to support

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address one of the parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address two of the parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to address all three of the parts specified in Requirement R2.
For the Requirement R3 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identifies the Emergency in its Reliability Coordinator Area failed to develop an action plan to resolve the Emergency during an instance where impacted Reliability Coordinators disagreed on the existence of Emergency.
R6	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identifies the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Emergency during an instance where Reliability Coordinators disagreed on the existence of the Emergency.
R7	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator had implemented its emergency procedures, unless such actions could not physically be implemented or would have violated safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted February 21, 2014 – March 24, 2014

First posting May 19, 2014 – July 2, 2014

Second posting August 6, 2014 – September 19, 2014

Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate.	01/20/06
2		Revised under Project 2006-06	Revised
2	August 4, 2011	Adopted by Board of Trustees	Revised
4	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** Coordination Among Reliability Coordinators

2. **Number:** IRO-014-3

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability:**

   4.1. Reliability Coordinator

5. **Effective Date**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.

6. **Background:**

   ~~On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards.~~

   ~~On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently-effective standards.~~

   ~~On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC~~

~~standards development process to ensure that a technically justified set of solutions is in place for reliability. That motion to defer action was granted on January 14, 2014.~~

~~On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report.~~

See Project 2014-03 project page.

~~**Rationale for Requirement R1**: Grammatical changes for consistency with defined terms to Requirement R1.~~

~~Deletions are due to duplication with proposed IRO-008-2, Requirements R4 and R6 and proposed IRO-010-3.~~

~~Other changes are grammatical for clarity.~~

B. Requirements and Measures

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations]*

1.1. Criteria and processes for notifications.

1.2. Energy and capacity shortages.

1.3. Control of voltage, including the coordination of reactive resources.

1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5. Provisions for periodic communications to support reliable operations.

M1. Each Reliability Coordinator shall have available the latest approved documented version of its Operating Procedures, Operating Processes, and Operating Plans that require notifications, or the coordination of actions among impacted Reliability Coordinators for conditions or activities that may impact adjacent Reliability Coordinator Areas. This documentation shall include dated, current in force documentation with the specified elements, and notes from periodic communications.

R2. Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-Day Operations]*

2.1. Review and update annually with no more than 15 months between reviews.

2.2. Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update.

2.3. Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.

M2. Each Reliability Coordinator shall have dated evidence that ~~the~~its Operating Procedures, Operating Processes, and Operating Plans that require one or more other Reliability Coordinators to take action were maintained as specified. This evidence may include but is not limited to dated documentation with confirmation of receipt, dated notice of acceptance or agreement to take specified actions, or dated electronic communications with confirmation of receipt and acceptance or agreement to take specified actions.

Rationale: Terminology changed from Adverse Reliability Impact to Emergency for consistency amongst standards. Emergency is a more inclusive term.

R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

M3. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings, or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, notified other impacted Reliability Coordinators.

R4. Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it operated as though an Emergency existed during each instance where Reliability Coordinators disagreed on the existence of an Emergency.

R5. Each Reliability Coordinator that ~~i~~Identifie~~d~~s an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

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R6. Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifie~~d~~s the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M6. Each impacted Reliability Coordinator shall have and provide evidence which may include but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent dated documentation, that will be used to determine that it implemented the action plan developed by the Reliability Coordinator who ~~has identified~~identifies the Emergency when Reliability Coordinators disagree on the existence of an Emergency unless such actions would have violated safety, equipment, regulatory, or statutory requirements.

Rationale for Requirement R7: Language added for consistency with proposed TOP-001-3, Requirement R7.

R7. Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M7. Each Reliability Coordinator shall make available upon request, evidence that requested assistance was provided, if able, to requesting Reliability Coordinators unless such actions could not be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If such a situation has not occurred, the Reliability Coordinator may provide an attestation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator shall retain its current, in force document and any documents in force since the last compliance audit for Requirements R1 and R2 and Measures M1 and M2.
- Each Reliability Coordinator shall retain its most recent 12 months of evidence for Requirement R5 and Measure M5.
- Each Reliability Coordinator shall retain 3-calendar years plus current calendar year of evidence for Requirement~~s~~ R6 and ~~R8 and Measures~~Measure M6~~ and M8~~.
- Each Reliability Coordinator shall retain evidence for 90-calendar days for operator logs and voice recordings and for the period since the last compliance audit for other evidence for Requirements ~~R7~~R3, R4, and ~~R9~~R7 and Measures ~~M7~~M3, M4, and ~~M9~~M7.

If a Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations	Medium	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address one of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address two of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability but failed to address three of the topical areas identified in Parts 1.1 through 1.5.	The Reliability Coordinator failed to have Operating Procedures, Operating Processes, or Operating Plans in place for activities that require notification, or coordination of actions with impacted adjacent Reliability Coordinators to support Interconnection reliability. OR, The Reliability Coordinator failed to implement its Operating Procedures, Operating processes, or Operating Plans when activities required notification, or coordination of actions with impacted adjacent Reliability Coordinators to support

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interconnection reliability.
R2	Operations Planning, Same-Day Operations	Lower	N/A	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address one of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address two of the ~~criteria~~parts specified in Requirement R2.	The Reliability Coordinator has Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 but failed to ~~meet~~address all three of the ~~criteria~~parts specified in Requirement R2.
For the Requirement ~~R5~~R3 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size. If a Reliability Coordinator has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The Reliability Coordinator did not notify one other impacted Reliability Coordinator upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify two other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify three other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.	The Reliability Coordinator did not notify four or more other impacted Reliability Coordinators upon identification of an expected or actual Emergency in its Reliability Coordinator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator failed to operate as though the Emergency existed during an instance where Reliability Coordinators disagreed on the existence of an Emergency.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that identifie~~d~~s the Emergency in its Reliability Coordinator Area failed to develop an action plan to resolve the Emergency during an instance where impacted Reliability Coordinators disagreed on the existence of Emergency.
R6	Real-time Operations, Same-Day Operations	High	N/A	N/A	N/A	The impacted Reliability Coordinator failed to implement the action plan developed by the Reliability Coordinator that identifie~~d~~s the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Emergency during an instance where Reliability Coordinators disagreed on the existence of the Emergency.
R7	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator did not provide assistance to Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator ha~~s~~d implemented its emergency procedures, unless such actions could not physically be implemented or would ~~violate~~have violated safety, equipment, regulatory, or statutory requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Outage Coordination**
2. **Number: IRO-017-1**
3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Planning Coordinator
   - **4.5.** Transmission Planner
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in its Reliability Coordinator's outage coordination process. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R3: Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R4: The SDT has re-written Requirement R4 to show that the process starts with the Planning Assessments created by the Planning Coordinator and Transmission Planner and then those Planning Assessments are reviewed and reconciled as needed with the Reliability Coordinator. This is in response to comments in paragraph 90 of the FERC NOPR about directly involving the Reliability Coordinator in the planning process for periods beyond the present one year outreach as well as recommendations in the IERP. The re-write should not be construed as relieving the Reliability Coordinator of responsibilities in this area but simply as a reflection of how the process actually starts.

In the future, the SDT believes that such coordination should take place in the TPL standards and to support that position, the SDT has created an item in a draft SAR for TPL-001-4 that would revise Requirement R8 to make the Reliability Coordinator an explicit party in the review process described there.

In addition, the SDT will submit a request to the Functional Model Working Team to adjust the roles and responsibilities of the Reliability Coordinator to this new paradigm.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it jointly developed solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing all four of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator's outage coordination process.
R3	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its Planning Assessment to impacted Reliability Coordinators.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 15, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
1	April 2014	New standard developed by Project 2014-03	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Outage Coordination**
2. **Number: IRO-017-1**
3. **Purpose:** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Transmission Operator
   - **4.3.** Balancing Authority
   - **4.4.** Planning Coordinator
   - **4.5.** Transmission Planner
5. **Effective Date:**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: This standard is in response to issues raised in NOPR paragraph 90 and recommendations made by the Independent Expert Review Panel and SW Outage Report on the need for an outage coordination standard. It allows for one cohesive standard to address all outage coordination concerns as opposed to having multiple requirements spread throughout the various standards.

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identify applicable roles and reporting responsibilities including:

1.1.1. Development and communication of outage schedules.

1.1.2. Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).

1.2. Specify outage submission timing requirements.

1.3. Define the process to evaluate the impact of Transmission and ~~generator~~generation outages within its Wide Area.

1.4. Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

M1. Each Reliability Coordinator shall make available its dated, current, in force outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator and Balancing Authority shall provide evidence upon request that it performed the functions specified in its Reliability Coordinator's outage coordination process. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R3: Planning Assessment is a defined term and a document that Planning Coordinators and Transmission Planners already have to produce for approved TPL-001-4. It is not a compilation of load flow studies but a textual summary of what was found in those studies including rationales and assumptions.

R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning~~Long-term Planning]*

M3. Each Planning Coordinator and Transmission Planner shall provide evidence upon request showing that it provided its Planning Assessment to impacted Reliability Coordinators. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

Rationale for Requirement R4: The SDT has re-written Requirement R4 to show that the process starts with the Planning Assessments created by the Planning Coordinator and Transmission Planner and then those Planning Assessments are reviewed and reconciled as needed with the Reliability Coordinator. This is in response to comments in paragraph 90 of the FERC NOPR about directly involving the Reliability Coordinator in the planning process for periods beyond the present one year outreach as well as recommendations in the IERP. The re-write should not be construed as relieving the Reliability Coordinator of responsibilities in this area but simply as a reflection of how the process actually starts.

In the future, the SDT believes that such coordination should take place in the TPL standards and to support that position, the SDT has created an item in a draft SAR for TPL-001-4 that would revise Requirement R8 to make the Reliability Coordinator an explicit party in the review process described there.

In addition, the SDT will submit a request to the Functional Model Working Team to adjust the roles and responsibilities of the Reliability Coordinator to this new paradigm.

R4. Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator, and Transmission Planner shall provide evidence upon request showing that it jointly developed solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Reliability Coordinator shall retain its dated, current, in force, outage coordination process in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it followed its Reliability Coordinator outage coordination process in accordance with Requirement R2 and Measurement M2.

Each Planning Coordinator and Transmission Planner shall retain evidence for three calendar years that it has its Planning Assessment to impacted Reliability Coordinators in accordance with Requirement R3 and Measurement M3.

Each Reliability Coordinator, Planning Coordinator, and Transmission Planner shall retain evidence for three calendar years that it has coordinated solutions within the Reliability Coordinator Area for identified issues or conflicts with planned outages in the Planning Assessment in accordance with Requirement R4 and Measurement M4.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing one of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing two of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing three of the parts specified in Requirement R1 (Parts 1.1 – 1.4).	The Reliability Coordinator did develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area but it was missing all four of the parts specified in Requirement R1 (Parts 1.1 – 1.4). OR, The Reliability Coordinator did not develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not perform the functions specified in its Reliability Coordinator's outage coordination process.
R3	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not provide its Planning Assessment to impacted Reliability Coordinators.

R #	Time Horizon	VRF	Violation Severity Levels			
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R4	Operations Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Transmission Planner did not jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Time Horizon: The official definition of the Operations Planning Time Horizon is: "operating and resource plans from day-ahead up to and including seasonal." The SDT equates 'seasonal' as being up to one year out and that these requirements covers the period from day-ahead to one year out.

Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in proposed IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC’s Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to monitor facilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2,

Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed TOP-002-4. All of the requirements were assigned a Medium VRF.

VRF for Proposed TOP-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

* FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
* FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
* FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R3:

* FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
* FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
* FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
* FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R4:

* FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
* FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
* FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in proposed TOP-003-3. Four of the five requirements were assigned a "Low" VRF: Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for Proposed TOP-003-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator and proposed TOP-003-3, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: approved IRO-010-1 for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R5, has only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-001-4. All of the requirements were assigned a “High” VRF.

VRF for Proposed IRO-001-4, Requirement R1:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking actions to preserve reliability.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to act, or direct others to act, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R2:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore, this requirement is also assigned a High VRF.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to comply with Operating Instructions could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R3:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of the inability to follow an Operating Instruction could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-002-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to give operators the authority to approve planned outages and maintenance of telecommunication, monitoring and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-003-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have adequate monitoring systems with emphasis on cited criteria could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

There are six requirements in proposed IRO-008-2. Four of the six requirements were assigned a "Medium" VRF: Requirements R1, R2, R3, and R6. The other requirements were assigned a "High" VRF.

VRF for Proposed IRO-008-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an Operational Planning Analysis in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement and there are no comparable requirements to compare against. It is a coordination requirement in the operational planning timeframe so this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate an Operating Plan in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify entities of roles in Operating Plans in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure that a Real-time Assessment is performed at least once every 30 minutes could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. However, that requirement combines operations planning and Real-time. This requirement only applies to Real-time which in the belief of the SDT raises the VRF to High.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of roles in plans in the Real-time environment could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R15 which is assigned a Medium VRF. The requirements are similar in that proposed IRO-008-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3 is for Transmission Operators. Hence, this requirement is also assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of when exceedances have been mitigated will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-010-2. Two of the requirements, Requirements R1 and R2, are assigned "Low" VRFs. Requirement R3 is assigned a "Medium" VRF.

VRF for Proposed IRO-010-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R2.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the data requested does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed IRO-014-3. Four of the requirements, Requirements R4, R5, R6, and R7, were assigned a "High" VRF. Requirements R1 and R3 were assigned a "Medium" VRF. Requirement R2 was assigned a "Low" VRF.

VRF for Proposed IRO-014-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-014-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have and implement the plans and procedures, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Low VRF. The requirement is for maintenance of plans, processes, and procedures. Hence, the designation of a Low VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to maintain the plans, processes, and procedures is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other Reliability Coordinators, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.2) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R7 which has a High VRF assignment. The requirements are similar in that proposed TOP-001-3, Requirement R7 is for Transmission Operators and Balancing Authorities while proposed IRO-014-3, Requirement R9 is for Reliability Coordinators. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-017-1. All four of the requirements have been assigned a "Medium" VRF.

VRF for Proposed IRO-017-1, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a coordination process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Medium VRF. The requirement is for following the process described in proposed IRO-017-1, Requirement R1 which is assigned a Medium VRF. Hence, the designation of a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to follow the process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved TPL-001-4 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the assessments, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate solutions, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the “default” for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. Those VSLs tried to gradate the provision of data. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity supplies the data or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT has assigned these VSLs to be binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about complying with the Operating Instruction which has a binary Severe VSL in approved IRO-001-1.1. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about informing the Reliability Coordinator which has a single Moderate VSL in approved IRO-001-1.1. The SDT believes that such a failure should be classified as binary Severe under current guidelines.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R1. Those VSLs are gradated and the SDT has followed that pattern here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R8. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity has supplied the authority or it hasn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-003-2, Requirement R1. Those VSLs tried to gradate the degree of monitoring. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is doing the monitoring or it isn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R4. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is providing adequate monitoring facilities with the particular emphasis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-008-1, Requirement R1. Those VSLs tried to gradate the performance of the Operational Planning Analysis by the number of days in a month that it wasn't available. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity performs the analysis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no comparable requirement to compare against. The SDT believes that this is a binary situation where an entity performs the coordination activity or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs gradated the notification efforts. The SDT has followed a similar path and assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R2. Those VSLs gradated the performance of Real-time Assessments based on time increments. The SDT made a similar assignment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs partially gradated the notification elements. The SDT has followed a similar path but assigned a complete set of incremental VSLs here consistent with current accepted practice.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-001-3, Requirement R15. Those VSLs are set up as a binary Severe situation but that requirement only involves notifying one entity, the Reliability Coordinator. There are potentially many more entities involved with this requirement so the SDT has set up a gradated set of VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-014-1, Requirement R1. Those VSLs present an incremental approach and the SDT has continued that approach.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement with no comparable requirement to follow. There are a number of criteria cited for the requirement and this lends itself to an incremental approach for the VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs are presented in an incremental approach. Therefore, the SDT has assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.2. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs tried to gradate things but the only differential is whether evidence was provided or not – actions themselves are covered in Severe. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity develops a plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.1. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity implements the plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed TOP-001-3, Requirement R7. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to proposed IRO-005-3.1a, Requirement R6 which has gradated VSLs and the SFT has adopted that approach here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no similar requirement in the Reliability Standards. The responsible entity either follows the process or it doesn't. Attempting to increment the effort doesn't make sense. Therefore, this VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to approved TPL-001-4, Requirement R8. In that case, the VSLs are incremental. However, the responsible entities there are dealing with many other entities. In this case, the responsible entity is dealing only with Reliability Coordinators which makes an incremental approach unnecessary due to the much smaller number of involved entities. Therefore, the VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar in nature to proposed IRO-017-1, Requirement R1. The VSL has been assigned in a similar manner – binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards

Final Ballots Now Open through October 20, 2014

Now Available

Final ballots and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for **TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1** are open through **8 p.m. Eastern on Monday, October 20, 2014**.

Additionally, final ballots for **IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan** are open through **8 p.m. Eastern on Monday, October 20, 2014**.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pools associated with this project may log in and submit their vote for the standards, definitions, implementation plan and associated VRFs and VSLs as described above by clicking here**.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Final Ballot and Non-Binding Poll Results

Now Available

Final ballots for **TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1** concluded at **8 p.m. Eastern, Monday, October 20, 2014**. The non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Wednesday, October 22, 2014**

Additionally, final ballots for **IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan** concluded at **8 p.m. Eastern, Monday, October 20, 2014.**

The standards achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results	Non-Binding Poll Results
	Quorum /Approval	Quorum/Supportive Opinions
IRO-001-4	90.77% / 82.64%	N/A
IRO-002-4	89.97% / 85.96%	N/A
IRO-008-2	89.71% / 83.73%	78.59% / 85.88%
IRO-010-2	89.97% / 86.22%	N/A
IRO-014-3	89.71% / 89.88%	78.59% / 91.33%
IRO-017-1	89.97% / 82.58%	78.89% / 92.18%
TOP-002-4	89.71% / 84.76%	78.89% / 86.77%
TOP-003-3	90.50% / 86.55%	78.30% / 82.29%
2 Definitions	88.39% / 94.07%	NA
Implementation Plan	88.39% / 91.84%	NA

Background information for this project can be found on the project page.

Next Steps

The standards and associated documents will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson,
Standards Developer, or by telephone at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-03 TOP-002-4
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	340
Total Ballot Pool:	379
Quorum:	**89.71 % The Quorum has been reached**
Weighted Segment Vote:	84.76 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	69	0.802	17	0.198	0	7	12
2 - Segment 2	9	0.7	6	0.6	1	0.1	0	1	1
3 - Segment 3	83	1	50	0.735	18	0.265	0	8	7
4 - Segment 4	30	1	20	0.952	1	0.048	0	6	3
5 - Segment 5	82	1	48	0.8	12	0.2	0	13	9
6 - Segment 6	52	1	32	0.744	11	0.256	0	4	5
7 - Segment 7	2	0	0	0	0	0	0	1	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**379**	**7**	**238**	**5.933**	**60**	**1.067**	**0**	**42**	**39**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
				SUPPORTS

1	KAMO Electric Cooperative	Walter Kenyon	Negative	THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		

1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Great River Energy	Brian Glover	Affirmative	

3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	

4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	

5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS

6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 TOP-003-3_Final_Ballot
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	343
Total Ballot Pool:	379
Quorum:	**90.50 % The Quorum has been reached**
Weighted Segment Vote:	86.55 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	73	0.849	13	0.151	0	7	12
2 - Segment 2	9	0.7	5	0.5	2	0.2	0	1	1
3 - Segment 3	83	1	62	0.886	8	0.114	0	7	6
4 - Segment 4	30	1	23	0.958	1	0.042	0	3	3
5 - Segment 5	82	1	56	0.836	11	0.164	0	7	8
6 - Segment 6	52	1	40	0.889	5	0.111	0	3	4
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.4	3	0.3	1	0.1	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**379**	**7.3**	**273**	**6.318**	**42**	**0.982**	**0**	**28**	**36**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	COMMENT RECEIVED - Mike Hill
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	

1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	

3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish	John D Martinsen	Affirmative	

	County			
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	

5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	

6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	NO COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2014-03 IRO-008-2
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	340
Total Ballot Pool:	379
Quorum:	**89.71 % The Quorum has been reached**
Weighted Segment Vote:	83.73 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	58	0.806	14	0.194	0	21	12
2 - Segment 2	9	0.7	6	0.6	1	0.1	0	1	1
3 - Segment 3	83	1	41	0.719	16	0.281	0	19	7
4 - Segment 4	30	1	15	0.882	2	0.118	0	10	3
5 - Segment 5	82	1	44	0.83	9	0.17	0	21	8
6 - Segment 6	52	1	28	0.824	6	0.176	0	12	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.1	1	0.1	0	0	0	2	0

10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**379**	**7**	**204**	**5.861**	**49**	**1.139**	**0**	**87**	**39**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
				SUPPORTS THIRD

1	KAMO Electric Cooperative	Walter Kenyon	Negative	PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		

3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
	Constellation Energy Control & Dispatch,			

4	L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	

5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Abstain	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	

10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-014-3
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	340
Total Ballot Pool:	379
Quorum:	**89.71 % The Quorum has been reached**
Weighted Segment Vote:	89.88 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	70	0.933	5	0.067	0	18	12
2 - Segment 2	9	0.7	5	0.5	2	0.2	0	1	1
3 - Segment 3	83	1	56	0.949	3	0.051	0	17	7
4 - Segment 4	30	1	16	0.941	1	0.059	0	9	4
5 - Segment 5	82	1	49	0.925	4	0.075	0	21	8
6 - Segment 6	52	1	34	0.944	2	0.056	0	11	5
7 - Segment 7	2	0	0	0	0	0	0	1	1
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	1	1
9 - Segment 9	3	0.2	1	0.1	1	0.1	0	1	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**379**	**7**	**241**	**6.292**	**19**	**0.708**	**0**	**80**	**39**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	

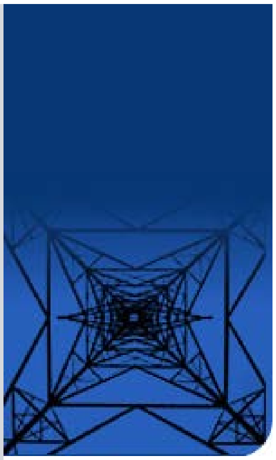
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	

3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		

5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS

5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	



9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Negative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-03 IRO-017-1
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Final
Total # Votes:	341
Total Ballot Pool:	379
Quorum:	**89.97 % The Quorum has been reached**
Weighted Segment Vote:	82.58 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	65	0.774	19	0.226	0	9	12
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	83	1	51	0.75	17	0.25	0	8	7
4 - Segment 4	30	1	18	0.9	2	0.1	0	7	3
5 - Segment 5	82	1	49	0.778	14	0.222	0	11	8
6 - Segment 6	52	1	32	0.744	11	0.256	0	4	5
7 - Segment 7	2	0	0	0	0	0	0	1	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**379**	**7.2**	**235**	**5.946**	**65**	**1.254**	**0**	**41**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Negative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Negative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS

1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY

				COMMENTS
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Negative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	

5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	

6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Negative	COMMENT RECEIVED
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	

8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-002-4
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	269
Total Ballot Pool:	341
Summary Results:	78.89% of those who registered to participate provided an opinion or an abstention; 86.77% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	

1	Duke Energy Carolina	Doug E Hils		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Abstain	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Abstain	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)

1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	

2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	COMMENT RECEIVED
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	COMMENT RECEIVED
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart		
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	

3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Abstain	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	

3	Sho-Me Power Electric Cooperative	Jeff L Neas	Abstain	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	

5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	

5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support Joe O'Brien's comments on behalf of David Austin.)
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	

6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp		
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	

6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-003-3
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	267
Total Ballot Pool:	341
Summary Results:	78.30% of those who registered to participate provided an opinion or an abstention; 89.29% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Abstain	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Abstain	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Affirmative	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	

1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	

3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart		
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Abstain	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	

3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Abstain	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	

5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	SUPPORTS THIRD PARTY COMMENTS - (ICLP comments submitted on 9.17.14)
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	

5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp		
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	

6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	

10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-008-2
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	268
Total Ballot Pool:	341
Summary Results:	78.59% of those who registered to participate provided an opinion or an abstention; 85.88% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Abstain	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Abstain	
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	

1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (OGE)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		

NERC

1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Negative	COMMENT RECEIVED
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	COMMENT RECEIVED
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	

3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart		
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Abstain	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments.)
3	New York Power Authority	David R Rivera	Abstain	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support OG&E's Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	

3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Abstain	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas		

4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	

5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp		
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Abstain	

6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	NO COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-014-3
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	268
Total Ballot Pool:	341
Summary Results:	78.59% of those who registered to participate provided an opinion or an abstention; 91.33% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Abstain	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Abstain	
1	Manitoba Hydro	Jo-Anne M Ross	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments)
1	Nebraska Public Power District	Jamison Cawley	Abstain	

1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	

1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	

3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart		
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Abstain	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Abstain	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	

5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)

5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp		
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Abstain	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	

6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Abstain	
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 IRO-017-1
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	269
Total Ballot Pool:	341
Summary Results:	78.89% of those who registered to participate provided an opinion or an abstention; 92.18% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Abstain	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Abstain	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	

1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula		
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	

3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart		
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Abstain	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Reveiw Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	

3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Abstain	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	

4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine		
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	

5	Ingleside Cogeneration LP	Michelle R DAntuono	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur		
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	

5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri		
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson		
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp		
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		

6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Abstain	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - **4.5.** Load-Serving Entity
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to ensure the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each

Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. 'Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures. These changes are in response to IERP recommendations.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that requested assistance, if able, was provided to other Transmission Operators unless such assistance cannot be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 - 83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15. The term 'sustained' was added to the requirement to indicate that notification is not required for momentary events.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area:

10.1.1. Facilities,

10.1.2. The status of Special Protection Systems, and

10.1.3. Non-BES facilities identified as necessary by the Transmission Operator and

10.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

10.2.1. Facilities,

10.2.2. Status of Special Protection Systems, and

10.2.3. Non-BES facilities.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities, the status of Special Protection Systems, and non-BES facilities as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time

Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the system to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20: Added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area . *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, and R14 through R20 and Measure M1 through M11, and M14 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.
R3	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide assistance to other Transmission Operators, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform one known	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform two known	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more known impacted Balancing Authorities or more 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one impacted interconnected entity or 5% or less of the negatively impacted entities, whichever is greater, of a sustained outage of telemetering and control equipment, monitoring and assessment capabilities, and	The responsible entity did not notify two impacted interconnected entities or more than 5% and less than or equal to 10% of the negatively impacted entities, whichever is greater, of a sustained outage of telemetering and control equipment, monitoring and	The responsible entity did not notify three impacted interconnected entities or more than 10% and less than or equal to 15% of the negatively impacted entities, whichever is greater, of a sustained outage of telemetering and control equipment, monitoring and assessment capabilities,	The responsible entity did not notify its Reliability Coordinator of a sustained outage of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more impacted interconnected entities or more than 15% of the negatively impacted NERC

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			associated communication channels between the affected entities.	assessment capabilities, and associated communication channels between the affected entities.	and associated communication channels between the affected entities.	registered entities of a sustained outage of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and non-BES facilities. .
R11	Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL Tv.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL had been exceeded.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the	The Transmission Operator did not have data exchange capabilities with two identified entity, or more than 5% or less than or equal to 10%	The Transmission Operator did not have data exchange capabilities with three identified entity, or more than 10% or less than or equal to 15% of	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			applicable entities, whichever is greater.	of the applicable entities, whichever is greater.	the applicable entities, whichever is greater.	
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entity, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entity, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

White paper on SOL Exceedances to be placed here.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	October 2014
BOT	November 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - **4.5.** Load-Serving Entity
5. **Effective Date:**

   ~~The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted~~, or directed others to act by issuing Operating Instructions~~ to ensure the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act~~, or direct others to act by issuing Operating Instructions,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted~~, or directed others to act by issuing Operating Instructions~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

R6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. 'Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures. These changes are in response to IERP recommendations.

R7. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its ~~e~~Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that requested assistance, if able, was provided to other Transmission Operators unless such assistance cannot be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known ~~other~~ impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known ~~other~~ impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no Emergency has occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15. The term 'sustained' was added to the requirement to indicate that notification is not required for momentary events.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of sustained outages of telemetering ~~equipment,~~ and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and impacted interconnected ~~NERC registered~~ entities of ~~planned~~ sustained outages of telemetering ~~equipment,~~ and control equipment, monitoring and assessment capabilities, and associated communication channels . Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area:

10.1.1. Facilities,

10.1.2. ~~t~~The status of Special Protection Systems, and

~~**10.1.1.**~~**10.1.3.** ~~sub-100 kV~~Non-BES facilities identified as necessary by the Transmission Operator~~, within its Transmission Operator Area~~ and

10.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

10.2.1. Facilities,

10.2.2. Status of Special Protection Systems, and

~~**10.1.2.**~~**10.2.3.** Non-BES facilities. ~~neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors Facilities, the status of Special ~~p~~Protection Systems, and ~~sub-100 kV~~non-BES facilities ~~identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, ~~to ensure~~in order for ~~that~~ it ~~is~~to be able to perform its reliability functions. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, ~~to ensure~~in order for ~~that~~ it ~~is~~to be able to perform its reliability functions.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of ~~its~~ actions taken to return the system to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the system to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and ~~Real-time Assessment~~analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and ~~Real-time Assessment~~analysis capabilities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator ~~and Balancing Authority~~ shall ~~always~~ operate to the most limiting parameter in instances where there is a difference in SOLs. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator ~~and Balancing Authority~~ shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R~~2~~1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area ~~(Balancing Authority Area)~~. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its ~~Transmission Operator Area (~~Balancing Authority Area~~)~~. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R11, and R14 through R20 and Measure M1 through M11, and M14 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall each keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act~~, or direct others within its Transmission Operator Area to act,~~ to ~~ensure~~address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
R2	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act ~~or direct others within its Balancing Authority Area to act,~~ to ~~ensure~~address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.
R3	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Operations Planning,	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-Day Operations, Real-Time Operations					Operator of its inability to perform an Operating Instruction issued by its Transmission Operator.
R5	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide assistance to other Transmission Operators, ~~if~~when requested and able, ~~when~~and the requesting entity had implemented its ~~e~~Emergency procedures, and such actions could have been physically implemented and

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one ~~other~~ known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two ~~other~~ known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR,	The Transmission Operator did not inform three ~~other~~ known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three ~~other~~ known	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other known impacted Transmission Operators or more than 15% of the known impacted other Transmission Operators~~, whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR, The Transmission Operator did not inform one ~~other~~ known impacted Balancing Authorities or 5% or less of the known impacted ~~other~~ Balancing Authorities, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	The Transmission Operator did not inform two ~~other~~ known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted ~~other~~ Balancing Authorities, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted ~~other~~ Balancing Authorities, whichever is ~~less~~greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	conditions did permit such communications. OR, The Transmission Operator did not inform four or more ~~other~~ known impacted Balancing Authorities or more 15% of the known impacted ~~other~~ Balancing Authorities~~,~~ ~~whichever is less,~~ of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one impacted interconnected ~~NERC registered~~ entity or 5% or less of the negatively impacted ~~NERC registered~~	The responsible entity did not notify two impacted interconnected ~~NERC registered~~ entities or more than 5% and less than or equal to 10% of the negatively	The responsible entity did not notify three impacted interconnected ~~NERC registered~~ entities or more than 10% and less than or equal to 15% of the negatively impacted	The responsible entity did not notify its Reliability Coordinator of a ~~planned~~sustained outage of telemetering and control equipment, monitoring and assessment capabilities, ~~control equipment,~~ and

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			entities, whichever is ~~less~~greater, of a ~~planned~~sustained outage of telemetering and control equipment, monitoring and assessment capabilities, ~~control equipment,~~ and associated communication channels between the affected entities.	impacted ~~NERC registered~~ entities, whichever is ~~less~~greater, of a ~~planned~~sustained outage of telemetering and control equipment, monitoring and assessment capabilities, ~~control equipment,~~ and associated communication channels between the affected entities.	~~NERC registered~~ entities, whichever is ~~less~~greater, of a ~~planned~~sustained outage of telemetering and control equipment, monitoring and assessment capabilities, ~~control equipment~~ and associated communication channels between the affected entities.	associated communication channels. OR, The responsible entity did not notify four or more impacted interconnected ~~NERC registered~~ entities or more than 15% of the negatively impacted NERC registered entities~~, whichever is less,~~ of a ~~planned~~sustained outage of telemetering ~~equipment,~~and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	~~N/A~~ The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor one of the items listed in	~~N/A~~ The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not monitor two of the items listed in	The Transmission Operator did not monitor Facilities, the status of Special Protection Systems, and ~~sub-100 kV~~non-BES facilities. ~~identified as necessary by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R10, Part 10.2.	Requirement R10, Part 10.2.	~~(SOL) exceedances within its Transmission Operator Area~~.
R11	Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, ~~to ensure~~ in order for ~~that~~ it ~~is~~to be able to perform its reliability functions.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	~~-~~For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	~~The Transmission Operator did not perform Real-time Assessments.~~ ~~OR,~~ ~~-~~For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for ~~three~~four or

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions ~~being~~ taken to return the system to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and ~~Real-time Assessment~~analysis capabilities.
R17.	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its monitoring,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-Time Operations					telecommunications, and analysis capabilities.
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The ~~responsible entity~~Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one ~~applicable~~identified entity, or 5% or less of the applicable entities, whichever is ~~less~~greater.	The Transmission Operator did not have data exchange capabilities with two ~~applicable~~identified entity, or more than 5% or less than or equal to 10% of the applicable entities, whichever is ~~less~~greater.	The Transmission Operator did not have data exchange capabilities with three ~~applicable~~identified entity, or more than 10% or less than or equal to 15% of the applicable entities, whichever is ~~less~~greater.	The Transmission Operator did not have data exchange capabilities with four or more ~~applicable~~identified entities or greater than 15% of the applicable entities, whichever is ~~less~~greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one ~~applicable~~identified entity, or 5% or less of the applicable entities, whichever is ~~less~~greater.	The Balancing Authority did not have data exchange capabilities with two ~~applicable~~identified entity, or more than 5% or less than or equal to 10% of the applicable entities,	The Balancing Authority did not have data exchange capabilities with three ~~applicable~~identified entity, or more than 10% or less than or equal to 15% of the applicable entities,	The Balancing Authority did not have data exchange capabilities with four or more ~~applicable~~identified entities or greater than 15% of the applicable entities, whichever is ~~less~~greater.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				whichever is ~~less~~greater.	whichever is ~~less~~greater.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

White paper on SOL Exceedances to be placed here.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Unofficial Comment Form

Project 2014-03 Revisions to TOP/IRO Reliability Standards
TOP-001-3

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. EST **Monday, November 10, 2014**.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Additional information about this project is available on the project page.

Background Information - Project 2014-03 – Revisions to TOP/IRO Reliability Standards

On November 21, 2013, FERC issued a NOPR proposing to remand three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards and four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards. In the NOPR, FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."

In response, NERC filed a motion requesting that FERC defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process. That motion to defer action was granted on January 14, 2014.

The drafting team formed to address those concerns has made revisions to the TOP and IRO standards proposed to be remanded, along with several other IRO standards to provide consistency amongst the TOP and IRO standards, to address NOPR issues and recommendations made by the Independent Expert Review Panel, the IRO five-year review team, and the 2011 SW Outage Report. In the ballot that ended September 19, 2014, all of the standards except TOP-001-3 achieved greater than the required two thirds ballot pool approval. The SDT has reviewed stakeholder comments submitted in that comment period and made only clarifying and non-substantive changes to all of the standards except TOP-001. No changes were made to the definitions or implementation plan.

The SDT has made numerous changes in the third posting for proposed TOP-001-3 in order to respond to industry comments raised in the second posting.

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Commenters are reminded that this is not a forum for questioning the issues raised in the FERC NOPR of November 21, 2013 but to objectively evaluate the work of the SDT in responding to the issues raised in the NOPR, and the recommendations made by the Independent Expert Review Panel (IERP), the IRO FYRT, and the SW Outage Report.

Questions

1. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

Notice of Request to Waive the Standard Process

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

As required by Section 16 of the NERC Standard Processes Manual (SPM), this is official notice to stakeholders that the leadership of the Project 2014-03 Revisions to TOP and IRO Reliability Standards Drafting Team, the Project Management Oversight Subcommittee (PMOS) liaison for that project, Standards Committee (SC) chair, and NERC Standards Staff (Requesters) are requesting that the SC consider a waiver of the Standard Processes Manual. The Requesters ask to shorten the next formal comment and ballot period for draft standard TOP-001-3, and any subsequent comment formal comment and ballot periods prior to final ballot for that standard, from 45 days to 30 days, and to shorten the final ballot for TOP-001-3 from ten days to seven days, in order to meet a regulatory deadline. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process.

The SC will meet via teleconference to consider this waiver request no earlier than Thursday, October 9, 2014 (to comply with the five business day notice required by Section 16 of the SPM). The Standards Committee's teleconference will be noticed through an announcement and posted on the NERC website. Additional details about the waiver request are included below, and should a waiver be granted by the SC, it will be posted on the project page.

Justification for Current Waiver Request

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) proposing to remand three revised TOP Reliability Standards and four revised IRO Reliability Standards. In the NOPR FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed

TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

NERC's motion to defer action was granted on January 14, 2014.

The drafting team has developed a set of eight revised standards and one new standard to replace the standards that the NOPR proposed to remand. The standards have been posted for two 45-day comment periods and ballots, and in the ballot ending September 19, 2014, eight of the nine standards achieved greater than the required two-thirds weighted segment approval.

The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Laura Hussey,
Director of Standards Development, at laura.hussey@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Agenda Item 2
Standards Committee
October 9, 2014

Waiver Authorization for Project 2014-03: Revisions to TOP and IRO Reliability Standards

Action

Authorize a waiver of the Standard Processes Manual (SPM) to:

a) shorten the next additional formal comment period (and any subsequent additional formal comment periods) for draft standard TOP-001-3 from 45 days to 30 days, with a ballot and non-binding poll during the last seven days of the 30 day period; and

b) shorten the final ballot period from ten days to seven days.

Background

The leadership of the TOP/IRO Standard Drafting Team, NERC staff, and the PMOS liaison and Standards Committee (SC) chair have requested a waiver of the NERC Standards Processes Manual (SPM) as described in the actions above. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process. As required in Section 16, NERC provided stakeholders with notice of these waiver requests on October 2, 2014. If a waiver is authorized, NERC staff will post notice of the waiver on the project page and notify the NERC Board of Trustees Standards Oversight and Technology Committee.

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) proposing to remand three revised TOP Reliability Standards and four revised IRO Reliability Standards. In the NOPR FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

NERC's motion to defer action was granted on January 14, 2014.

The drafting team has developed a set of eight revised standards and one new standard to replace the standards that the NOPR proposed to remand. The standards have been posted for two 45-day comment periods and ballots, and in the ballot ending September 19, 2014, eight of the nine standards achieved greater than the required two-thirds weighted segment approval.

The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to: Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the recommendations from the Independent Expert Review Project and the SW Outage Report will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards to address concerns expressed in the NOPR a. Consider the inputs from technical conferences 2. Consider the recommendations in the Independent Expert Review Report and the SW Outage Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Preserve the intent of the reliability objectives in the current, approved standards so that no reliability gaps are created 5. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 6. Address the directives from Order 693 originally assigned to Projects 2006-06 and 2007-03.

SAR Information
7. Address the following directive from Order 693, paragraph 1855: *"Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities*."
8. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements.
9. Address the issue of outage coordination as pointed out by the Independent Experts Review Panel through the creation of a new standard.
10. Address the recommendations of the IRO Five Year Review Team (Project 2012-09) for the IRO standards revised in this project.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5 IRO-008-1 IRO-009-1 IRO-010-1a IRO-015-1 IRO-016-1	May need to be reviewed for language and terminology consistency with revisions made in this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A

Regional Variances	
SPP	N/A
WECC	N/A

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | Updated August 2014

This mapping document showing the translation of Requirements in the following currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions[1]
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

[1] TOP-006-2 is the currently enforceable version of this standard; TOP-006-3 was developed in response to a request for interpretation seeking clarification of Requirement R1 and does not substantively change the Requirements of TOP-006-2. In its NOPR proposing to remand the TOP and IRO standard, FERC proposed to approve TOP-006-3. The drafting team has mapped the Requirements in the new standards to TOP-006-3 because the Parts of Requirement R1 in TOP-006-3 more clearly delineate which entity has responsibility.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** The SDT proposes retiring Requirement R2 as the regional reliability plan is a high level overview "how" document that shows how a Reliability Coordinator will comply with other NERC Standards. As a result, this requirement is administrative and redundant to other measureable and enforceable requirements within the standards. Since the requirement is generally administrative, it does not materially impact the reliability of the BES. The Reliability Plan concept is a holdover from the transition period from the Operating Policies to the Version 0 standards and was used extensively in the readiness evaluation process by the Operating Committee. The template used for the Reliability Plan is actually an outline of Operating Policy 9. The material included in the plan was a description of how an entity satisfied the specific functional areas under Policy 9. With the transition of Policy 9 to the IRO and other standards, the items addressed in

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	the reliability plans are inherently addressed in the body of other more measurable Reliability Standards.
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or by issuing Operating Instructions. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3. **Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator may implement alternate remedial actions.	
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed COM-001-2 Requirement R1 for voice links and proposed IRO-002-2 Requirement R1 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed COM-001-2, Requirement R1:** **R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R1:** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Approved PER-004-2, Requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, Part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, Part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability	This requirement is replaced by proposed COM-001-2 Requirement R1 and proposed IRO-002-4 Requirement R2. **Proposed COM-001-2, Requirement R1:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	**R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R2:** **R2**. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirements R3 and R4:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to	This requirement is replaced by proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R4:** **R4**. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R3 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have	This requirement is replaced by proposed IRO-002, Requirement R2 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R2:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
procedures in place to mitigate the effects of analysis tool outages.	**R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunications, monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R3 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	This requirement is replaced by proposed IRO-001-4, Requirement R1 since Operating Instructions, regardless of what timeframe they are issued for, are issued in a Real-time environment. In addition, roles for entities identified in the Operating Plans built from Operational Planning Analyses are communicated in proposed IRO-008-2, Requirement R3. **Proposed IRO-001-4, Requirement R1:** R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed IRO-008-2, Requirement R3:** R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s).

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	Replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and	The first sentence is replaced by proposed IRO-002-4, Requirement R3. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R3**:

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by approved EOP-010-1, Requirements R1 through R3. **Approved EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R3, R5 and R6. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-34 Requirements R3 and R4. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-010-2, Requirements R1, Part 1.2, and R3.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	**Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-010-4, Requirement R1, Part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses; **2.1.4.** Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall	The requirement is replaced by proposed IRO-008-2, Requirements R3, R5, and R6. **Proposed IRO-008-2, Requirement R3:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	**R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R4. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R3 and R5. **Proposed IRO-008-2, Requirements R3 and R5:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, R6:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

<table>
<tr><th colspan="2">Standard IRO-010-1a Reliability Coordinator Data Specification and Collection</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following:

R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

R1.2. Mutually agreeable format.

R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).

R1.4. Process for data provision when automated Real-Time system operating data is unavailable.</td><td>This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3.

Proposed IRO-010-2, Requirement R1:
R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to:

1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

1.2 Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability.

1.3 A periodicity for providing data.

1.4 The deadline by which the respondent is to provide the indicated data.

Proposed IRO-010-2, Requirement R3:
R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol</td></tr>
<tr><td>R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.</td><td>This requirement is replaced by proposed IRO-010-2, Requirement R2.

Proposed IRO-010-2, Requirement R2:
R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td></tr>
</table>

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Criteria and processes for notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Provisions for periodic communications to support reliable operations.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1, Part 1.5:** **R1, Part 1.5:** Provisions for periodic communications to support reliable operations.
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R3.1**. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	This requirement is replaced by approved PRC-001-1.1, Requirement R3. **Approved PRC-001-1.1, Requirement R3:** **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **3.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **3.2** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R3 through R6 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. **Proposed IRO-014-3, Requirement R4:** **R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R5:** **R5**. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R6:** **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014 as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism. The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent in proposed TOP-001-4, Requirement R1 which states that the Transmission Operator must act or issue Operating Instructions.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R1: **R1.** Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-2, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-2, R2: **Proposed IRO-001-2, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-2, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R4: **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance at the Transmission Operator level is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. Balancing Authorities provide assistance under approved EOP-001-2.1b, Requirement R1. **Approved EOP-001.2.1b, Requirement R1:** **R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities**.** **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Each Transmission Operator shall assist other Transmission Operators, if requested and available, provided that the requesting entity has implemented its emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: **R7.1** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-010-2, Requirement R3:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – reactive power: Replaced by approved VAR-001-4, Requirement R3 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-4, Requirements R1 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved VAR-001-4, Requirement R3: **R3**. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	The Transmission Operator and Balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:**

<table>
<tr><th colspan="2">Standard TOP-002-2.1b — Normal Operations Planning</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td></td><td>R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Approved MOD-001-1a, Requirement R1:
R1. Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area.

Approved MOD-030-2, Requirement R3:
R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that …

Approved MOD-001-1a, Requirement R2:
R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s).

Proposed IRO-017-1, Requirement R2:
R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator’s outage coordination process.</td></tr>
<tr><td>R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.</td><td>Coordination of plans is covered in proposed IRO-017-1, Requirement R2 and proposed IRO-008-2, Requirement R2.

Proposed IRO-017-1, Requirement R2:
R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator’s outage coordination process.

Proposed iRO-008-2, Requirement R2:
R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.</td></tr>
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Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-4, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-006-4, Requirement R5, and proposed TOP-002-4, Requirement R4. **Approved INT-006-4, Requirement R5:** **R5**. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Authorities have been removed from the applicability of this requirement. SOLs and IROLs are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13. Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs. Second sentence – SOLs are set by the Transmission Operator in approved FAC-014-2, Requirement R2 according to the methodology distributed by the Reliability Coordinator in approved FAC-011-2, Requirement R4, Part 4.3. This should assure that SOLs are consistent for common facilities. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved FAC-014-2, Requirement R2:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: 4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	2.4 Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act, or direct others to act by issuing Operating Instructions, to ensure the reliability of its Balancing Authority Area. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
14.2 Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5, Part 5.2:** **5.2** A mutually agreeable process for resolving data conflicts

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

<table>
<tr><th colspan="2">Standard TOP-003-1 — Planned Outage Coordination</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.</td><td>Generator Operators will provide planned outage information to Transmission Operators and Balancing Authorities through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2.

Proposed TOP-003-3, Requirement R5:

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Proposed TOP-003-3, Requirement R1:

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification …

Proposed IRO-017-1, Requirement R2:

R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.</td></tr>
<tr><td>R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.</td><td>This requirement is replaced by proposed TOP-001-3, Requirement R9. The data specification concept in proposed TOP-003-3 requires entities to provide data as requested. If there are outages of the equipment needed for providing that data, the entity experiencing the outage must notify the entity it is sending data to so that proper arrangements can be made for replacing the data or coming up with a plan to live without it. It is expected that the data specifications would incorporate such concepts.

Proposed TOP-001-3, Requirement R9:
R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.</td></tr>
</table>

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, Requirement R2 and proposed IRO-017-1, Requirement R1, Part 1.4. **Proposed IRO-017-1, Requirement R1, Part 1.4**: **1.4** Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators **Proposed IRO-008-2, Requirement R2:** **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14 and proposed TOP-002-4, Requirement R2.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. **Approved FAC-014-2, Requirement R2:** **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Operator may take such actions, as it deems necessary, to protect its area.	Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: **6.1** Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-4, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R10, R12 and R14. **R6.2** has been replaced by proposed TOP-001-3, Requirement R8. **R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: R1.1. Within its Transmission Operator Area:

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R1.1.1. Facilities, **R1.1.2.** The status of Special Protection Systems, and **R1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and R1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **R1.2.1.** Facilities, **R1.2.2.** Status of Special Protection Systems, and **R1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, Part 3.3:** **3.3** A mutually agreeable security protocol **Proposed TOP-003-3, Requirement R5, Part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: R1.1. Within its Transmission Operator Area: **R1.1.1.** Facilities, **R1.1.2.** The status of Special Protection Systems, and **R1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and R1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **R1.2.1.** Facilities, **R1.2.2.** Status of Special Protection Systems, and **R1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R3, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: R1.1. Within its Transmission Operator Area: **R1.1.1.** Facilities, **R1.1.2.** The status of Special Protection Systems, and **R1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and R1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R1.2.1. Facilities, **R1.2.2.** Status of Special Protection Systems, and **R1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, Part 1.2; proposed TOP-003-3, Requirement R1, Part 1.2; and proposed TOP-003-3, Requirement R2, Part 2.2.; and the proposed changes to the definitions of Operational Planning Analysis and Real-time Assessment. **Proposed definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-010-2, Requirement R1, Part 1.2: **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R2, Part 2.2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: R1.1. Within its Transmission Operator Area: **R1.1.1.** Facilities, **R1.1.2.** The status of Special Protection Systems, and **R1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and R1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **R1.2.1.** Facilities, **R1.2.2.** Status of Special Protection Systems, and **R1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to:
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R3, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R3**: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R10: **R10.** Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: R1.1. Within its Transmission Operator Area: **R1.1.1.** Facilities, **R1.1.2.** The status of Special Protection Systems, and **R1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and R1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **R1.2.1.** Facilities, **R1.2.2.** Status of Special Protection Systems, and **R1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R5 and R6. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-008-2, Requirement R5: **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4.** When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1 and approved IRO-009-1, Requirement R4. **Approved IRO-=009-1, Requirement R4:** **R4**. When actual system conditions show that there is an instance of exceeding an IROL in

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R6. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

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System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this

approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the

maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.

4. **Voltage Stability Limits:**
Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

<u>Facility Rating Exceedance</u>

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

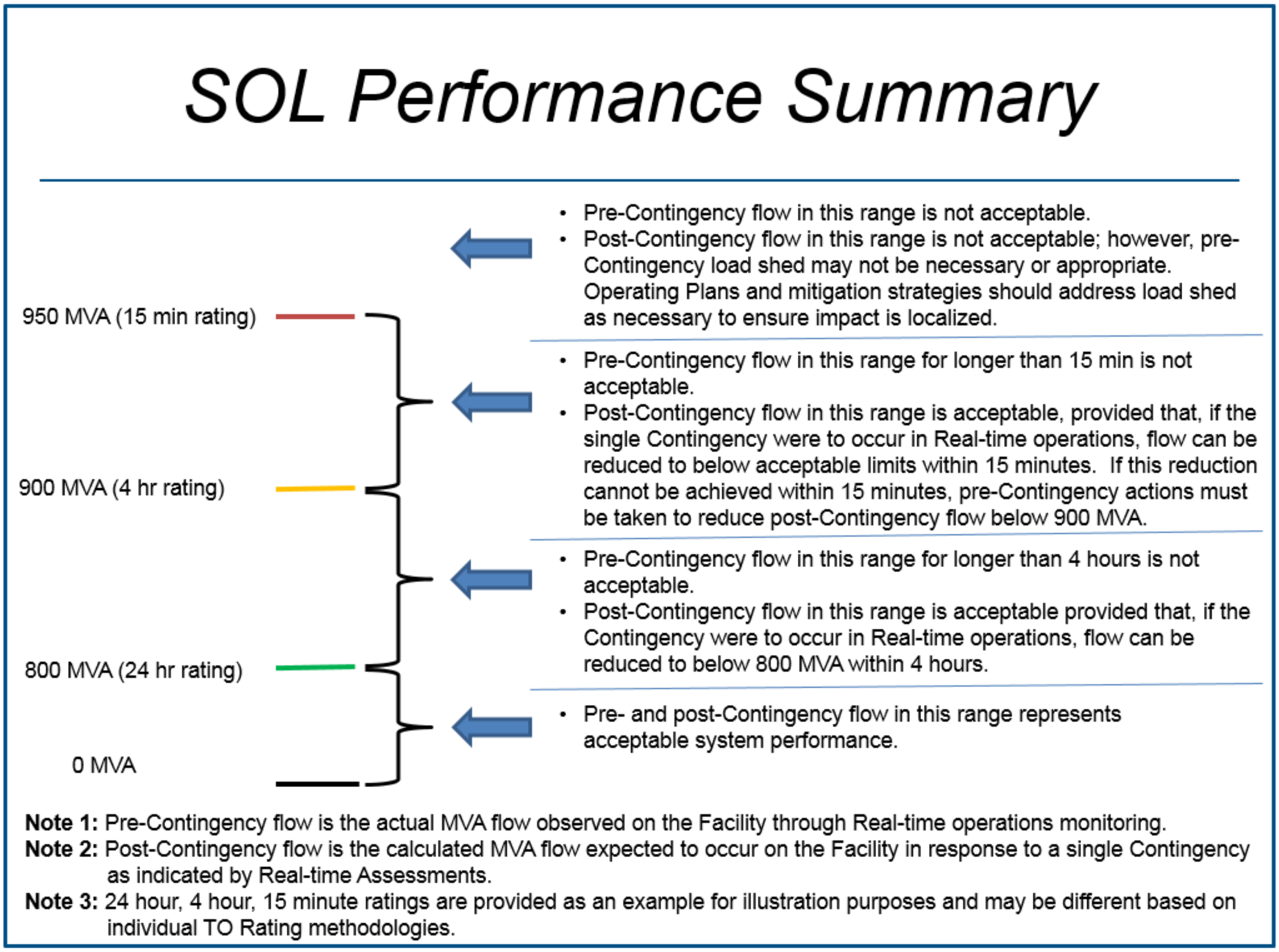

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

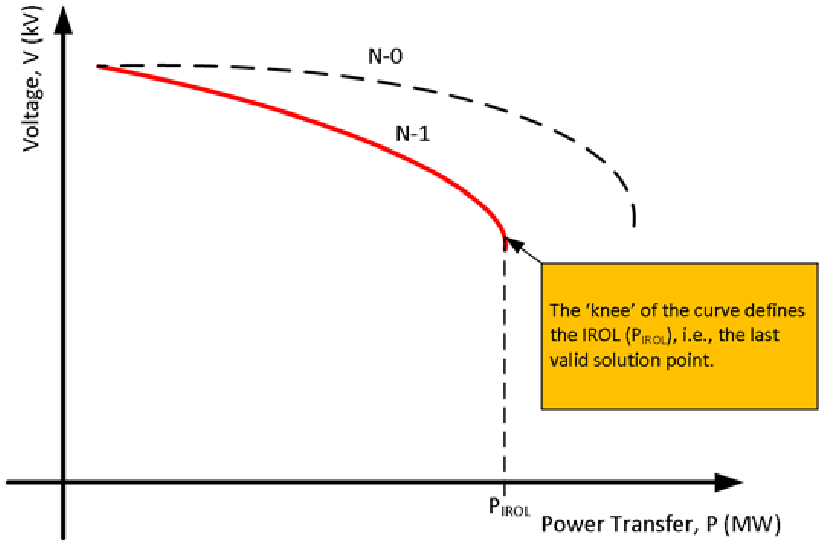

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in Operating Plan.	Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.
Emergency (4 hr)	All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in Operating Plan.	Use available effective actions and emergency procedures except Load shed consistent with timelines identified in Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in Operating Plan.	All of the above however, Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their ~~Normal~~ applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable ~~Emergency (short-term)~~ Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this

approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs. ~~Conversely, if an area has plenty of headroom on thermal Facility Ratings and has no risk of instability but is prone to low voltages pre- or post-Contingency, then the voltage limits in that area are the limiting SOLs.~~

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity~~How an entity remains within these SOLs can vary depending on the practices and mechanisms employed by that entity~~. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.

3. **Transient Stability Limits:**
Transmission Operators establish SOLs to prevent ~~unit/intra-area instability,~~ intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.

4. **Voltage Stability Limits:**
Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage ~~s~~Stability criteria are met.~~Voltage Stability limits are typically defined as the maximum power transfer or load level for which a post-Contingency solution can be reached.~~ Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

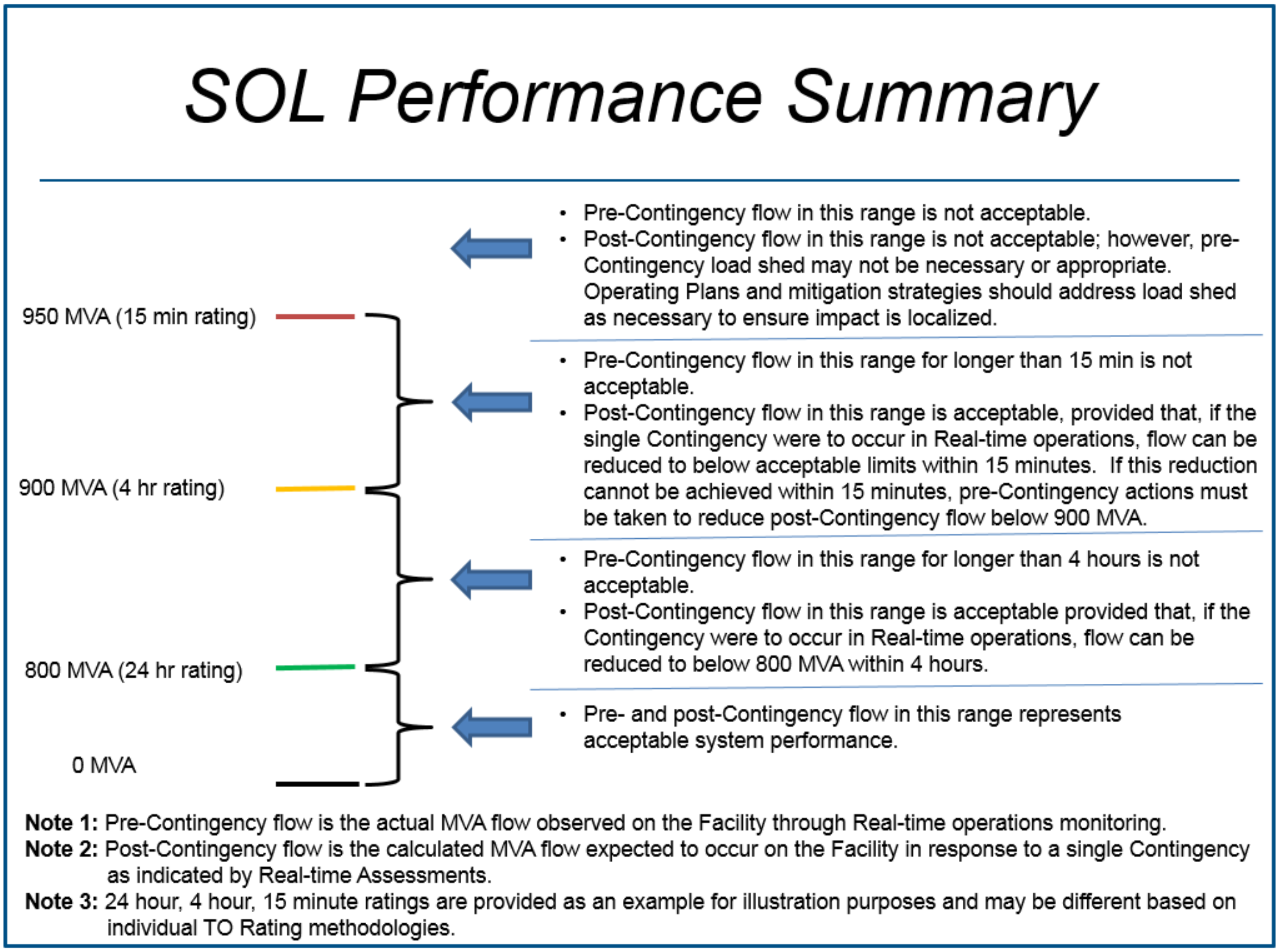

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

<u>Steady State Voltage Limit Exceedance</u>

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

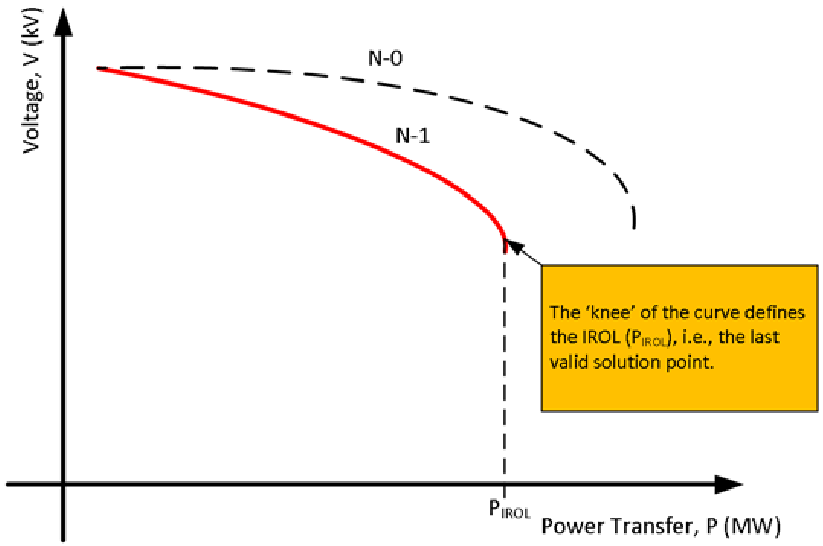

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above.   For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal Limit Exceeded	**Pre-Contingency (actual) Loading**	**Post-Contingency (calculated) Loading**
Normal (24 hr)	**~~Non-cost~~Reconfiguratione actions, Redispatch~~off-cost~~ actions, emergency procedures except ~~l~~Load shed consistent with timelines identified in Operating Plan.**	**Trend – continue to monitor. Take reconfiguration ~~non-cost~~ actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.**
Emergency (4 hr)	**All of the above plus ~~l~~Load shed only if necessary and appropriate to control loading below 4 hr ~~violation below~~ Emergency Rating consistent with timelines identified in Operating Plan.**	**Use available~~all~~ effective actions and emergency procedures except ~~l~~Load shed consistent with timelines identified in Operating Plan.**
Emergency (15 min)	**All of the above plus ~~l~~Load shed to control loading ~~violation~~ below 15 min Emergency Rating consistent with timelines identified in Operating Plan.**	**All of the above however, ~~l~~Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.**

~~Legend~~
~~NON-COST~~RECONFIGURATION
~~OFF-COST~~REDISPATCH

~~LOAD SHEDDING~~

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

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Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

Plan and Operate within all System Operating Limits

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

SDT Consideration:

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability

Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

SDT consideration:

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load

conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

1.1. Within its Transmission Operator Area:

1.1.1. Facilities,

1.1.2. The status of Special Protection Systems, and

1.1.3. Non-BES facilities identified as necessary by the Transmission Operator and

1.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:

1.2.1. Facilities,

1.2.2. Status of Special Protection Systems, and

Non-BES facilities.

> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

SDT consideration:

See previous response.

Compliance with Reliability Directives

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

SDT consideration:

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. The proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that sub-100 kV data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES

data and external network data as deemed necessary by the Transmission Operator.

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT discussed this concern and concluded that an explicit requirement to use the data was an unnecessary administrative concern.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. These requirements will dictate what external data a Transmission Operator needs to acquire.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) “will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility

Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

See previous responses for this heading.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

<u>SDT consideration:</u>

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

<u>SDT consideration:</u>

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-

2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

> Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

> Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

> <u>SDT consideration:</u>
>
> See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

> <u>SDT consideration:</u>
>
> Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

> <u>SDT consideration:</u>
>
> The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

> <u>SDT consideration:</u>
>
> The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.
>
> > Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
> >
> > **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency)

> and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers this situation.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R5 that uses only actual and projected Emergency covering all time horizons.

> Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

Proposed IRO-014-2, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
1.2 Specify outage submission timing requirements.

1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, Part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, sub-100 kV data, and applicable relay data are included.

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to have a coordinated Operating Plan(s) which will have required the Reliability Coordinator to have reviewed the plans submitted by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, Part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, Part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here. The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, Parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	elements operated at less than 100 kV on BPS reliability.	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Proposed TOP-003-3, Requirement R1, part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-contingency operating conditions.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R13**: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures**.**	**Proposed TOP-001-3, Requirement R14**: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, Part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		(Real-time Assessment may be provided through internal systems or through third-party services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	Model parameters are outside the scope of this project.
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for sub-100 kV data and monitoring as deemed necessary by the reliability entities. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **1.1.** Within its Transmission Operator Area: **1.1.1.** Facilities, **1.1.2.** The status of Special Protection Systems, and **1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and **1.2.** Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **1.2.1.** Facilities, **1.2.2.** Status of Special Protection Systems, and **1.2.3.** Non-BES facilities. **Proposed IRO-002-4, Requirement R4**: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **1.3.** Within its Transmission Operator Area: **1.3.1.** Facilities, **1.3.2.** The status of Special Protection Systems, and **1.3.3.** Non-BES facilities identified as necessary by the Transmission Operator and **1.4.** Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **1.4.1.** Facilities, **1.4.2.** Status of Special Protection Systems, and **1.4.3.** Non-BES facilities. **Proposed IRO-002-4, Requirement R4:**

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	(1) Phase angle calculation tools are outside the scope of this project. (2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.	limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability. Training is outside the scope of this project.

Project 2014-03 - Revision of TOP/IRO Reliability Standards

Resolution of Issues and Directives

The following table contains a list of all FERC directives, industry issues, and Independent Expert Review Panel (IERP) recommendations associated with the standards being revised in Project 2014-03, with proposed resolutions.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	892. Consider commenters' suggestions as part of the standards development process. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.	The SDT has added measures for all requirements. The Regional Reliability Organization has been removed from the standards.
IRO-001-3	FERC Order 693	893. Consider commenters' suggestions as part of the standards development process. FirstEnergy	The SDT has considered the commenter's suggestions and believes that safety refers to any

Standard	Source	Language	Resolution
		suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.	type of safety including personal or equipment and that no additional wording is necessary. If a generator receives conflicting Operating Instructions, the generator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.
IRO-001-3	FERC Order 693	895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.	The SDT has considered the comments and believes that a Reliability Coordinator can direct a Qualifying Facility (registered as a GO or GOP) to act through the issuance of Operating Instructions. Therefore, no additional requirements are necessary.
IRO-001-3	FERC Order 693	896. Eliminate the references to the regional reliability organization as an applicable entity. Paragraph 896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 to substitute "Regional Entity" for "regional reliability organization" and reflect	The SDT has removed all references to the Regional Reliability Organization from the standards.

Standard	Source	Language	Resolution
		NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	
IRO-001-3	FERC Order 693	897. Consider adding measures and levels of non-compliance. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	The SDT has added measures and Violation Severity levels (VSLs) (which replaced levels of non-compliance) for each requirement.
IRO-001-3	FERC's December 20, 2007 and April 4, 2008 Orders	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance	The SDT has established requirements that apply to the Load-Serving Entity. **Proposed TOP-001-3, Requirement R3**: **R3.** Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it

Standard	Source	Language	Resolution
		filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define “Non-Asset Owning LSEs” as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been	would violate safety, equipment, regulatory, or statutory requirements.

Standard	Source	Language	Resolution
		incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability First (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf)	

Standard	Source	Language	Resolution
		· NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.	
IRO-001-3	Fill in the Blank Team	Remove ", sub-region, or interregional coordinating group" from R1	Terms have been removed from the standard.
IRO-001-3	Version 0 Team	Inability to perform needs to be communicated	Clarity has been provided to address this issue throughout the various standards.
IRO-001	Version 0 Team	What is meant by 'interest of other entity'?	The SDT proposes to retire Requirement R9. All Reliability Coordinator Standard Requirements are developed so that the Reliability Coordinator shall act in the interest of reliability for the Reliability Coordinator Area and the Interconnection.
IRO-001-3	Fill in the Blank Team	Consider removing "Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market	The purpose statement has been revised accordingly.

Standard	Source	Language	Resolution
		participant over another." from the Purpose section of the standard.	Purpose: To establish the responsibility of Reliability Coordinators to act or direct other entities to act to prevent an Emergency.
IRO-001-3	NERC Audit Observation Team	All applicable registered functions shall comply with RC directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Inform the RC immediately of the inability to perform such directives. For audit purposes, what is acceptable evidence?	Measure M2 contains the provisions for suitable evidence. **Proposed IRO-001-4, Measure M2**: **M2**. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instruction, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator’s Operating Instruction. If no event has occurred, the Transmission Operator, Balancing Authority, Generator Operator, or

Standard	Source	Language	Resolution
			Distribution Provider may provide an attestation that an event has not occurred.
IRO-001-3	VRFs Team	R6 - Since the RC must be NERC certified, it stands to reason that anyone performing RC tasks should be certified. However, since the RC still retains the accountability for actions, and requirement 4 handles the agreements, this requirement is a medium risk.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
IRO-001-3	IERP	Requirement R1 content is incomplete. IERP recommended addressing 3 concepts as follows: RC has the authority to direct others to act. RC has the obligation to direct others to act to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.	The NERC Functional Model v5 spells out the authority of the Reliability Coordinator on page 30 under the description of the Reliability Coordinator functional entity. Proposed IRO-001-4, Requirement addresses the obligation of the Reliability Coordinator to direct others to act. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. The term 'Reliability Directive' has been replaced with the defined term 'Operating Instruction.' Proposed COM-002-4 determines the protocol for issuing Operating Instructions.

Standard	Source	Language	Resolution
		When directing others to act in accordance with this requirement, a RC must identify its directive as a "Reliability Directive". Consider consolidating with other authority-related standards and COM-003 in a single Authority standard as follows: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.	The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-001-3	IERP	IERP viewed Requirement R2 language as unclear and unable to be practically implemented. Questioned whether equipment requirements were a valid reason for not complying with RC direction. IERP proposed covering this requirement under a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.

Standard	Source	Language	Resolution
		safety, equipment, regulatory, or statutory requirements.	
IRO-001-3	IERP	IERP viewed content of Requirement R3 as incomplete by not requiring a reason for not complying with the RC's direction IERP recommended consolidating into a single Authority standard (see requirement above, which would replace both IRO-001 requirements R2 and R3)	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.
IRO-002-1	FERC Order 693	905 - Require a minimum set of tools that must be made available to the reliability coordinator. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.	This directive is beyond the scope of this project and will be resolved in a future project.
IRO-002	Version 0 Team	R5 – define synchronized information system	The term is not used in the revised standards.
IRO-002	Version 0 Team	R7 – define 'adequate' tools and 'wide-area'	The terms are not used in the revised standards
IRO-002-1	Version 0 Team	Words such as 'easily understood' and 'particular emphasis' need to be tightened	The terms are not used in the revised standards
IRO-002-3	IERP	IERP viewed Requirement R1 as incomplete. RC also needs to approve any other work being done on the tools, hardware/software/telecom systems within the RC that could affect the quality and the content of the data coming into the control center.	Proposed IRO-002-4, Requirement R2 addresses this issue. **Proposed IRO-002-4, Requirement R2**: **R2**. Each Reliability Coordinator shall provide its System Operators with the authority to approve

Standard	Source	Language	Resolution
		Also consider consolidating with Project 2009-02 Requirement R1 was proposed for consolidation under a new Authority standard: Authority R2 Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.	planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-002-3	IERP	IERP viewed Requirement R2 as incomplete. Procedures need to address not only tools outages, but also tools maintenance or other inhibitors to quality performance of analysis tools. Also consider consolidating with Project 2009-02	The SDT added 'maintenance' approval to proposed IRO-002-3, Requirement R3. This includes all work being done on monitoring and analysis capabilities and not just those that will cause an outage. **Proposed IRO-002-4, Requirement R2**: **R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Standard	Source	Language	Resolution
			The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards.
IRO-003	Order 693	914. … we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area …	The term is not used in the revised standards. The proposed data specification concept allows for the Reliability Coordinator to ask for any reliability related data that it needs in order to fulfill its reliability tasks thus obviating the need for a specific criteria for determining critical facilities. And specific requirements for monitoring have been added for the Reliability Coordinator. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
IRO-004-1	Order 693	934. In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each	Measures have been added to all requirements.

Standard	Source	Language	Resolution
		Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	
IRO-004-1	Order 693	935. …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency	The SDT has addressed this issue in proposed IRO-008-2 and TOP-002-4 as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. SOLs must be controlled according to the Operating Plan which is set up on time-based facility ratings (see SOL Exceedance White Paper for further details). IROLs are controlled to the IROL T_v which by definition is always less than 30 minutes. Approved IRO-009-1, Requirement R1 also addresses this item. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard	Source	Language	Resolution
			Proposed TOP-002-4, Requirement R1: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed IRO-009-1, Requirement R1**: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
IRO-005	FERC Order 693	520. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have	The SDT addresses the need for Reliability Coordinator assessment and approval on a requirement by requirement basis. For example, see proposed IRO-008-2, Requirements R3 and R6.

Standard	Source	Language	Resolution
		impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR. 525. Accordingly, we direct the ERO to include a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities, including how to determine whether an action needs to be assessed by the reliability coordinator. This Requirement is best developed under the Reliability Standards development process including the consideration whether this Requirement should be included in this communications Reliability Standard or an operating Reliability Standard.	**Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R5**: **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
IRO-005-1	FERC Order 693	946. "Conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROLS, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to NERC.	Completed and filed in Oct 2008
IRO-005-1	FERC Order 693	950- Provide further clarification that reliability coordinators and transmission operators direct control	The SDT has proposed IRO-001-4, Requirement R1 to address the Commission's suggestion for

Standard	Source	Language	Resolution
		actions, not LSEs as part of the standard development process. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.	clarification. Proposed TOP-001-4, Requirement R1 also addresses this issue. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed TOP-001-4, Requirement R1:** **R1.** Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
IRO-005-1	FERC Order 693	951-"Measures and levels of non-compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency, and causes of the violations and whether these occur during normal or contingency conditions. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO-005-1through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration,	The SDT has added measures and VSLs (which replaced levels of non-compliance) for each requirement.

Standard	Source	Language	Resolution
		frequency and causes of the violations and whether these occur during normal or contingency conditions.	
IRO-005-1	Fill in the Blank Team	R14 has regional reference	The term is not used in the revised standards.
IRO-005-1	Version 0 Team	R10, 11 & 12 – RA not empowered to do this	RA is no longer an applicable entity in the revised standards.
IRO-005-4	IERP	Requirement R1 is incomplete--needs to include Emergency. Requirement R1 reads: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. Also - there are gaps between the old std IRO-005-3 R2 to IRO-005-4: missing is: There is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard	The SDT replaced Adverse Reliability Impact with Emergency in all requirements. Emergency is a broader term. Proposed IRO-002-4, Requirement R3 addresses the issue of monitoring. **Proposed IRO-002-4, Requirement R3**:

Standard	Source	Language	Resolution
		and Disturbance Control Standard requirements. (Minus strikethrough) FROM IRO-005-3 R9: Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. The SDT believes all appropriate items, including Special Protection System evaluation and awareness is addressed through the revised definitions of Real-time Assessment and Operations Planning Analysis. The data specification has been revised to explicitly address Special Protection Systems. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1. Part 1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
		From IRO-005-3 R10: In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	The SDT has addressed the issue of resolving differences in limits in proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R18**: **R18.** Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.

Standard	Source	Language	Resolution
		Recommend consolidating with IRO-008 R3.	The SDT has consolidated requirements and standards as it believes appropriate.
IRO-005-4	IERP	The proposed standard creates a gap in outage coordination by proposing to retire IRO-005-3 R6. This could be resolved through an Authority standard as proposed by the IERP From IRO-005-3 R6: The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The SDT has proposed a new standard, IRO-017-1 Outage Coordination, to address this issue.
IRO-005-4	IERP	Requirement R2 should also include Emergency Requirement R2 reads: Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated. Note: there is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1	The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency.

Standard	Source	Language	Resolution
		Recommend moving to IRO-008 and create an R4	
IRO-014-2	IERP	Gap in Requirement R1 - Need to identify RC's authority to direct another RC to take action - suggestion: create another Requirement, i.e., R6 (in proposed authority standard). Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT does not agree with this recommendation. A Reliability Coordinator does not direct another Reliability Coordinator. Proposed IRO-014-3 describes how to coordinate between Reliability Coordinators.
IRO-014-2	IERP	R2 is administrative and should be deleted	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R3 implements plan from R1; it should be combined with R1	The SDT believes that combining the requirements would create a complex requirement with multiple objectives that would be difficult to measure for compliance.
IRO-014-2	IERP	Requirement R4 is administrative and should be deleted.	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R5 should require notification of “all IMPACTED RCs"; not "ALL"	The SDT has added ‘impacted’ to appropriate locations in the standards.
IRO-014-2	IERP	R6 should be consolidated with other standards that incorporate the concept of operating to the most conservative for reliability - IRO-009-1 R5	Approved IRO-009-1 only addresses IROLs. Proposed IRO-014-3 addresses all limits.

Standard	Source	Language	Resolution
		R6 reads: During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.	
IRO-014-2	IERP	Requirement R7 should be retired. The reliability objective is covered under R6, and also supported by IRO-009-1 R5	The SDT believes that the two requirements are sufficiently distinct to warrant separateness. Requirement R6 speaks to actual operations. Requirement R7 speaks to having an established plan. The SDT believes that reliability is best served by having a plan to follow.
IRO-014-2	IERP	Requirement R8 should be retired. The reliability objective is covered under R6.	The SDT does not agree with this recommendation. Requirement R8 is a separate requirement.
IRO-016	VRF's Team	R1.2.1 & R2 – ambiguous	Requirement R2 was approved for retirement by FERC effective January 2014. Requirement R1, part 1.2.1 was incorporated in the set of requirements in proposed IRO-014-3, and ambiguous language has been deleted.
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in

Standard	Source	Language	Resolution
			the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This concern is addressed in proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	The term is not used in the revised standards
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been revised to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is

Standard	Source	Language	Resolution
			listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-001-2	IERP	Requirement R1 phrase "unless it violates requirements" is too permissive or there may be a better way to phrase it Consider consolidating TOP-001-2 Requirements R1 and R2 and all other standards requirements related Authority to into a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under [Authority standard R1] unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT believes that this is well understood language. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
TOP-001-2	IERP	The language “emergency assistance” in Requirement R4 is unclear. When and how must assistance be rendered, and what type? BA’s should be included as functional entity. Consider moving R4 to EOP standards (this is an "emergency" operating requirement)	The SDT revised the language for clarity and included the Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7**. Each Transmission Operator shall assist other Transmission Operators, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate

Standard	Source	Language	Resolution
			safety, equipment, regulatory, or statutory requirements.
TOP-001-2	IERP	Requirement R5 should also include notification of Emergencies (in addition to ARI), and should include Bas. R5 states: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.	The SDT added impacted Balancing Authorities. The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-2	IERP	R6 needs to include real time outages of telecom as well as planned outages. Requirement should be covered under COM-001	The SDT added telecommunications to the requirement. **Proposed TOP-001-2, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between it and the affected entities. COM standards are not in scope for this project.

Standard	Source	Language	Resolution
TOP-001-2	IERP	Requirement R8 does not cover all information needed for reliability. It should cover 1) SOLs within a TOP's/RC's footprint, 2) SOLs that are within one TOP's/RC's footprint that could affect another entity and 3) an SOL that spans into 2 TOP's/RC's footprints The requirement should also obligate the TOP to also inform impacted TOPs (The entity that could be impacted must tell the TOP that could impact them that it needs the info)	The SDT has addressed issue 1 in proposed TOP-001-3, Requirement R15. SOLs that cross boundaries are taken care of at the Reliability Coordinator level. **Proposed TOP-001-3, Requirement R15:** **R15**. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the system to within limits when a SOL has been exceeded.
TOP-002-3	Order 693	1597. Consider ISO-NE recommendation that the reference to "transmission service provider" in TOP-002-2 R12 be replaced by TOP and/or TO. Requirement R12 states: The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.	This requirement is now addressed by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **R6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or

Standard	Source	Language	Resolution
			A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3**: **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. Approved MOD-030-2, Requirement R2.4: Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
TOP-002-3	Order 693	1598. Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including non-BES data as necessary. Next-day analysis is performed using Operational Planning Analysis. Approved NUC-001-2.1 also applies here. **Proposed IRO-010-2, Requirement R1 and Part 1.1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-

Standard	Source	Language	Resolution
			time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed Definition: Operational Planning Analysis** - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs

Standard	Source	Language	Resolution
			including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
TOP-002-3	Order 693	1600. Address critical energy infrastructure confidentiality as part of the routine standard development process	The data specification standards now contain provisions for addressing security of data. **Proposed IRO-010-2, Requirement R3, Part 3.3**: **R3. Part 3.3** A mutually agreeable security protocol. **Proposed TOP-003-3, Requirement R5, Part 5.3:** **R5. Part 5.3** A mutually agreeable security protocol.
TOP-002-3	Order 693	1601. …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages	SOLs are the responsibility of the Transmission Operator and IROLs are the responsibility of the Reliability Coordinator. This issue is addressed in proposed changes to the IRO standards. Approved IRO-009-1, Requirement R1 also applies. **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R2: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3**: **R3**. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
TOP-002-3	Order 693	1606. Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm	The SDT agrees and has addressed the issue in proposed TOP-002-3, Requirement R4, part 4.4:

Standard	Source	Language	Resolution
		load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.
TOP-002-3	Order 693	1608. Require simulation contingencies to match what will actually happen in the field	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly. The definitions require Contingencies to match field conditions as they require evaluations against projected system conditions for Operational Planning Analysis and system conditions for Real-time Assessment. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The

Standard	Source	Language	Resolution
			assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
TOP-002-3	IERP	Requirement R1. TOP-008-1 R4 needs to be incorporated into TOP-002-3 requirement R1. Also - the definition of "Operational Planning Analysis" provides too much latitude in time. Recommend removing the parenthesis in the definition; the entity will make the determination and document (documentation is evidence) the applicability of what it uses for their next day study	The SDT revised the definition of Operating Planning Analysis and Requirement R1. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next

Standard	Source	Language	Resolution
			day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
TOP-003-0	FERC Order 693	1620. …direct the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these type of issues, specifically proposed IRO-017-1, Requirement R1. This new standard takes into account the recommendations from the Independent Expert Review Panel and SW Outage Report and brings all of the various outage coordination issues into one cohesive standard. **Proposed IRO-017-1, Requirement R1:** **R1**. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of Project 2007-03 in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional

Standard	Source	Language	Resolution
			standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. In response to concerns raised by the IERP and the SW Outage Report, the SDT has developed proposed IRO-017-1 Outage Coordination. This standard requires the development of a coordinated outage process between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. If so desired, a Reliability Coordinator could include lead times in its process. (See proposed IRO-017-1, Requirement R1, Part 1.2.) In addition, proposed IRO-010-2 and TOP-003-2 dealing with data specifications could also cover this issue. The data specification must include any and all data required by the Reliability Coordinator, Transmission Operator and Balancing Authority. Planned outage data and timings could be included in such a data specification.

Standard	Source	Language	Resolution
			Therefore, the SDT has not included a standard lead time in the revised requirements. **Proposed IRO-017-1, Requirement R1, Part 1.2:** **1.2** Specify outage submission timing requirements.
TOP-003-0	Order 693	1622. Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these types of issues. **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	Order 693	1624. Direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and Part 1.1**: **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time

Standard	Source	Language	Resolution
			monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
TOP-003-2	IERP	Requirements R1 and R2 do not address level of accuracy required; see if this is provided elsewhere (i.e. project 2009-02) Consolidate R1 and R2 at minimum; at max consolidate with RC (IRO-010-1a R1)	Level of accuracy is one of the issues identified in the Real-Time Tools Best Practices Task Force Report. NERC is currently instituting a review of all of the recommendations in various reports, including the Real-time Tools Best Practices Task Force report, to see what actions should be taken, if any are still required, to address recommendations in the reports. The SDT does not want to consolidate the two responsibilities. The industry has clearly indicated a desire for separate standards for the Reliability

Standard	Source	Language	Resolution
			Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Consolidate R3 and R4 at minimum; at max consolidate with RC (IRO-010-1a R2)	The SDT does not want to consolidate the two requirements or the two standards. The SDT feels Requirements R3 and R4 are for different tasks. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Requirement R5 should be consolidated with IRO-010-1a R3	The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	The SDT believes that this issue has been addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment, and the requirement for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances. The SDT has developed a white paper on the topic of SOL exceedance to explain the technical rationale behind this resolution. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known

Standard	Source	Language	Resolution
			Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R1**: **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances

Standard	Source	Language	Resolution
			identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14**: **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
TOP-004-1	Order 693	1637. …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Completed and filed in Oct 2008.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (… the Commission proposed to interpret “multiple outages” in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an	The SDT feels that approved EOP-001-2.1b dealing with emergency operations planning covers the intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, approved FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under … high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	Order 693	1639. Consider Santa Clara's comment in the SDT process. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows	The data specification standards require that entities obtain all of the data that they need to perform their reliability functions. This would include frequency, voltages, real and reactive power flows, and any other data that the entity needs. Proposed TOP-001-3, Requirements R10 and R11 also address this item. **Proposed IRO-010-2, Requirement R1**: **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-001-3, Requirement R10**:

Standard	Source	Language	Resolution
			R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **1.1.** Within its Transmission Operator Area: **1.1.1.** Facilities, **1.1.2.** The status of Special Protection Systems, and **1.1.3.** Non-BES facilities identified as necessary by the Transmission Operator and **1.2.** Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: **1.2.1.** Facilities, **1.2.2.** Status of Special Protection Systems, and **1.2.3.** Non-BES facilities. **Proposed TOP-001-3, Requirement R11:** **R11**. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.

Standard	Source	Language	Resolution
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	The SDT has clarified the issue. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL $T_{v.}$
TOP-005	Order 693	1648. ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1.	The SDT has added specific parts to the data specification standards as well as revising the definitions of Operational Planning Analysis and Real-time Assessment to address this issue. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not

Standard	Source	Language	Resolution
			limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-005	Order 693	1650. Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process. FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. ISO-NE recommends that the reference to "purchasing-selling entity" should be replaced with LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-3. Requirement R4 has been superseded by proposed TOP-003-3 which does include the indicated entities and has deleted PSE. **Proposed TOP-003-3, Requirement R5**: **R5.**Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in

Standard	Source	Language	Resolution
			Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
TOP-005	Order 693	1651. … deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.	The SDT believes that confidentiality is a market issue and not a reliability issue and as such it does not belong in the Reliability Standards. However, security of information is a reliability concern and the SDT has addressed that issue through the addition of requirements for establishing security protocols in data exchanges. **Proposed TOP-003-3, Requirement R5, Part 5.3**: 5.3 A mutually agreeable security protocol. **Proposed IRO-010-2, Requirement R3, Part 3.3**: 3.3 A mutually agreeable security protocol.
TOP-005	Order 693	1660. Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system	This directive is beyond the scope of this project and will be resolved in a future project.
TOP-006	Order 693	1665. Clarify the meaning of appropriate technical information concerning protective relays	That term is no longer used in the standards. To address concerns about the status of protection systems, the SDT has incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential

Standard	Source	Language	Resolution
			(post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**:

Standard	Source	Language	Resolution
			1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-006	Order 693	1664/1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	All requirements now have measures.
TOP-006	Order 693	1673. Direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan. NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.	Analysis is required in proposed TOP-002-3, Requirement R1 and in proposed TOP-001-3, Requirement R13. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1 and proposed TOP-001-3, Requirement R13 as shown in the revised definition of Operational Planning Analysis and Real-time Assessment. Additionally, approved NUC-001-2.1, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-3. Approved NUC-001-2, Requirements R3 & R8 cover the information flowing back to the nuclear plant operator. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable

Standard	Source	Language	Resolution
			inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13**:

Standard	Source	Language	Resolution
			R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved NUC-001-2.1, Requirement R3**: **R3**. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. **Approved NUC-001-2.1, Requirement R4.1**: 4.1 Incorporate the NPIRs into their operating analyses of the electric system. **Approved NUC-001-2.1, Requirement R8:** **R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.
VAR-001-1	Order 693 Transferred from Project 2013-04 Voltage and Reactive Control	1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of	The SDT has clarified the issue of having the Reliability Coordinator provide oversight. The proposed requirement uses the term 'Facilities' which is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt

Standard	Source	Language	Resolution
		reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	compensator, transformer, etc.)." Therefore, the requirement covers voltage and reactive resources. **Proposed IRO-002-4, Requirement R3**: **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
INT-006-1	Order 693 Transferred from Project 2008-12 Coordinate Interchange Standards	866. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that makes it applicable to reliability coordinators and transmission operators. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review	An equally efficient and effective method of addressing the directive was approved by the Board and filed with FERC by Project 2008-12 SDT by including the term 'Interchange' in the definition of Operational Planning Analysis. This change has been retained by Project 2014-03. Proposed IRO-008-2, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must

Standard	Source	Language	Resolution
		indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	consider Interchange when performing the study. Then, in proposed IRO-008-2, Requirement R2, the Reliability Coordinator must develop a plan for addressing the problem. Similar requirements exist for the Transmission Operator in proposed TOP-002-3. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**:

Standard	Source	Language	Resolution
			R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:** **R3**. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R3:**

Standard	Source	Language	Resolution
			R3. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC Operating Committee Response to NERC Standards Committee / RISC Triage of IEPR Gaps

April 2, 2014

The NERC Operating Committee reviewed three perceived gaps, Outage Coordination, Governor Frequency Response, and Situational Awareness, as identified by the Independent Experts in their June 2013 report. As an important step in this review, the OC's Executive Committee met via WebEx with the Independent Experts to more thoroughly discuss and understand the thinking which led to these elements being cited as possible gaps. During the WebEx, the OCEC and the Independent Experts also reviewed all of the proposed requirements in the Independent Experts draft Authority matrix. The results of the OC's discussions, and the Project 2014-03 SDT's consideration within the revised TOP and IRO standards for two of the three perceived gaps (Outage Coordination and Situational Awareness) are presented below. The third gap identified by the Independent Experts, Governor Frequency Response, is outside the scope of Project 2014-03.

Outage Coordination

Draft requirements 3, 7, 8 and 9 of the Independent Experts draft Authority Standard focus on Outage Coordination. One concern recognized the fact that the Reliability Coordinators have a wide area view and broader situational awareness, allowing for early identification and resolution of conflicts. Therefore the RCs should have the most influence on outage coordination. Further concerns identify standards that are currently in flux, particularly those remanded standards in which requirements are being removed.

Operating Committee opinion

The Operating Committee concurs that Outage Coordination is an important grid reliability function. Outage coordination should originate from the TOPs and GOPs; with conflicts resolved by their respective RC. It makes sense for this process to begin with a set of previously approved scheduled long term outages with a sufficient time margin for results to be incorporated into seasonal operating studies. Further, the RC should retain the authority for final approval up to the time the asset is removed from service, as well as recall authority (if technically feasible and appropriate to recall) as needed to prevent or mitigate emergencies.

Longer term outage coordination is necessary for those assets that require long maintenance planning pursuant to the type of work required, such as turbine rebuilds, nuclear refueling, etc. This likely belongs in the scope of the Planning Coordinator (PC) for outages planned more than 12-months into the future. A Reliability Standard could be written that requires PCs to coordinate long term outages and which requires responsible entities (e.g., GOs, TOs) to request a time slot in which to perform whatever maintenance is required.

In either case, during the longer term planning horizon, or the Operations planning and real time operations time frame, each PC or RC should have an understanding of the impacts on neighboring PCs or RCs when those assets are planned to be out or are forced out, with notification/coordination requirements with these PCs or RCs.

SDT response:

To enhance reliability, the Project 2014-03 SDT has provided explicit requirement language to address the need for planned outage coordination at the Reliability Coordinator level. See proposed IRO-014-3, Requirement R1, part 1.4. The Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address overall outage coordination issues.

Proposed IRO-014-3, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Situational Awareness (EMS RTCA models)

In this gap the Independent Experts recommend the development of a standard that defines the requirements for EMS RTCA models or performance expectations of the models (Project 2009-02 – Real Time Monitoring and Analyses Capabilities).

Operating Committee opinion

The Operating Committee has a concern that this gap could be interpreted as recommending a "HOW" standard where specific tools would be required even for the smallest TOPs, as opposed to a "WHAT" standard that would allow for other ways to accomplish the objective. In conversations with the Independent Experts it became clear that proper situational awareness was the primary concern. The OC concurs that real time contingency analysis process (real time updated topology and telemetry) should be performed on each BES facility. This functionality could be performed by use of an RTCA application at the TO or RC level, or coverage by alternate means would be appropriate.

SDT response:

The Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13. In addition, the Project 2014-03 SDT has revised the definition of Real-time Assessment to allow for contracting needed services to accommodate concerns for smaller entities.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase

angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Remainder of the draft Authority Standard Requirements

Authority R1

Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.

Operating Committee opinion

The current IRO-001-1.1 and TOP-001-1a are expected to be retired and replaced by IRO-001-3. In either case, these standards contain the authority to act, but the requirement to act appears to be implicit. The OC agrees that the RC, TOP and BA should explicitly be required to act.

SDT response:

The Project 2014-03 SDT agrees and has adjusted the wording in the standards to address this issue.

Proposed IRO-001-4, Requirement R1: Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R1: Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R2: Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instructions.

Authority R2

Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.

Operating Committee opinion

The current IRO-002-2 provides for the RC to have control of its tools but does not include the TOP or BA. IRO-002-2 is expected to be retired and replaced by IRO-002-3, which clarifies that the system operators have the authority to approve outages of analysis tools (The OC suggests adding “under the direct control of their company”), but does not include TOPs or BAs. The OC concurs

with the clarification in IRO-002-3, and the OC further agrees that TOPs and BAs should be included.

SDT response:

The Project 2014-03 has added proposed TOP-001-3, Requirements R16 and R17 to provide Transmission Operators and Balancing Authorities with capabilities similar to those of the Reliability Coordinator.

> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities.

> Proposed TOP-001-3, Requirement R17: Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunications, and analysis capabilities.

Authority R4

RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.

Operating Committee opinion

During the OCEC/Independent Expert webex, the Independent Experts explained that the objective of this requirement is to mandate the posting of a letter in the control rooms granting authority to the system operators to carry out their required tasks. While the Operating Committee believes this is a good practice, it does not believe that it rises to the level of a Standards Requirement.

SDT response:

The Project 2014-03 SDT agrees with the position of the Operating Committee Executive Committee. A letter of authority located in the Control Room is an example of good utility practice. A change to the requirements is not warranted.

Authority R5

Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

In relation to R1 above this understanding seems implicit. However, in the interest of clarity the OC would support this requirement.

SDT response:

The Project 2014-03 SDT agrees.

Proposed TOP-001-3, Requirement R3: Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed TOP-001-3, Requirement R5: Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Proposed IRO-001-4, Requirement R2: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Authority R6

Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

IRO-014-5, IRO-015-1 and IRO-016-1 describe inter RC procedures, Plans, notifications and coordination. These standards are expected to be retired and replaced by IRO-014-2 incorporating the pertinent requirements from the retiring standards. However, none of these standards explicitly include a requirement for one RC to comply with a directive from another RC.

The OC recognizes that coordination between RCs is vitally important. It is also recognized that an RC is the entity with the best understanding and situational awareness of its unique footprint. Therefore it is not believed to be beneficial for operational reliability for one RC to direct the actions of another RC. Rather, it is more appropriate to have this type of coordination documented within the requisite Joint Operating Agreements in which the appropriate assistance would be documented and understood in advance of such actions.

SDT response:

The Project 2014-03 SDT believes that proposed IRO-014-2 Requirements R3 – R6 already require Reliability Coordinators to coordinate and implement action plans even if the RC cannot agree that a problem exists or what the exact action plan is

> Proposed IRO-014-2, Requirement R3: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.
>
> Proposed IRO-014-2, Requirement R4: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R5: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R6: Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

TOP-001-3 ONLY

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in proposed IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-4 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as proposed IRO-002-4, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor facilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2,

Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the "default" for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the proposed IRO-002-2, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards IRO-001-3

Formal Comment Period Now Open through November 10, 2014

Now Available

A 30-day formal comment period for **TOP-001-3 – Transmission Operations** is open through **8 p.m. Eastern, Monday, November 10, 2014.**

On October 9, 2014, the NERC Standards Committee (SC) authorized a waiver of the standard development process, in accordance with Section 16 of the Standard Processes Manual, to meet the pending regulatory deadline for revisions to TOP and IRO standards. The SC approved a request to shorten the comment period for draft standard TOP-001-3 from 45 days to 30 calendar days, with an additional ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) to be conducted during the last 7 days of the comment period.

Instructions for Commenting

Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated VRFs and VSLs will be conducted **November 4-10, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards
IRO-001-3

Formal Comment Period Now Open through November 10, 2014

Now Available

A 30-day formal comment period for **TOP-001-3 – Transmission Operations** is open through **8 p.m. Eastern, Monday, November 10, 2014.**

On October 9, 2014, the NERC Standards Committee (SC) authorized a waiver of the standard development process, in accordance with Section 16 of the Standard Processes Manual, to meet the pending regulatory deadline for revisions to TOP and IRO standards. The SC approved a request to shorten the comment period for draft standard TOP-001-3 from 45 days to 30 calendar days, with an additional ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) to be conducted during the last 7 days of the comment period.

Instructions for Commenting

Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated VRFs and VSLs will be conducted **November 4-10, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards
TOP-001-3

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **TOP-001-3 – Transmission Operations** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Monday, November 10, 2014**.

The standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	Non-Binding Poll Results
Quorum /Approval	Quorum/Supportive Opinions
78.36% / 60.21%	79.18% / 63.33%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Mark Olson,
or by telephone at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2014-03 TOP-001-3_Additional_Ballot_November_2014
Ballot Period:	11/4/2014 - 11/10/2014
Ballot Type:	Successive
Total # Votes:	297
Total Ballot Pool:	379
Quorum:	**78.36 % The Quorum has been reached**
Weighted Segment Vote:	60.21 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	47	0.618	29	0.382	0	6	23
2 - Segment 2	9	0.5	2	0.2	3	0.3	0	2	2
3 - Segment 3	83	1	40	0.635	23	0.365	0	5	15
4 - Segment 4	30	1	15	0.652	8	0.348	0	2	5
5 - Segment 5	82	1	34	0.557	27	0.443	0	7	14
6 - Segment 6	52	1	20	0.571	15	0.429	0	3	14
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0	0	0	0	0	0	0	5
9 - Segment 9	3	0.2	0	0	2	0.2	0	1	0

10 - Segment 10	8	0.5	5	0.5	0	0	0	1	2
Totals	**379**	**6.2**	**163**	**3.733**	**107**	**2.467**	**0**	**27**	**82**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jason Snodgrass (GTC))
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		

1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC - RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (. MRO NSRF)
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments)
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support MRO NSRF Comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see NPCC comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox on behalf of Dave Austin - NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
				SUPPORTS THIRD PARTY

1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY (NPCC)
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli		

2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	COMMENT RECEIVED
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (georgia transmission corp)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC - RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	

3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF comments.)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox on behalf of David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina		

3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson from Central Lincoln PUD.)
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's Comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
				SUPPORTS THIRD PARTY

5	Amerenue	Sam Dwyer	Negative	COMMENTS - (Ameren's comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	

5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin (NIPSCO) comments.)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart		

5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (See single set of NIPSCO comments from Rob Fox/David Austin)
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	SUPPORTS THIRD PARTY COMMENTS - (NV Energy)
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NPCC)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel		
8		Debra R Warner		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett		
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	
9	New York State Public Service Commission	Diane J Barney	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-001-3
Poll Period:	11/4/2014 - 11/10/2014
Total # Opinions:	270
Total Ballot Pool:	341
Summary Results:	79.18% of those who registered to participate provided an opinion or an abstention; 63.33% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	NO COMMENT RECEIVED
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jason Snodgrass (GTC))
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)

NERC

1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments)
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (see npcc comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox on behalf of Dave Austin-NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	

1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council ("NPCC"))
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		

3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (georgia transmission corp)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC - RSC)
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		

3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Rob Fox on behalf of David Austin)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	COMMENT RECEIVED
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))

3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	

4	Wisconsin Energy Corp.	Anthony P Jankowski		
5	Acciona Energy North America	George E Brown		
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	

5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Austin (NIPSCO) comments.)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))

5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NIPSCO single set of comments from David Austin/Rob Fox)

6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council (“NPCC”))
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff		
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	

10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (47 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (18 Responses)
Lead Contact (18 Responses)
Question 1 (42 Responses)
Question 1 Comments (43 Responses)

Individual
Steve Alexanderson
Central Lincoln People's Utility District
Central Lincoln recently participated in a load shedding drill led by our Host BA/TOP. The single most glaring problem we saw was one of validation. In the past we had always thought we would validate an R3 Directive or Operating Instruction by calling the TOP back at a known phone number. Our TOP informed us that such a validation method would not be possible during a real event, since all phones and switchboards would likely be busy. While objecting to our validation method, the TOP has failed to offer a suitable one. This leaves Central Lincoln with the choice of responding to an Operating Instruction to shed load coming from a scammer who has easy access TOP-001 on line, or risking a possible violation. Suggest the SDT begin looking at the question of validation, since without a validation method R3 poses a greater risk to reliability than it addresses.
Group
Northeast Power Coordinating Council
Guy Zito
No
We commented in the last posting to replace the word “ensure” in requirements R1 and R2, and in the standard’s other requirements where applicable. We note that “ensure” has been replaced with “address”. The Purpose of the standard is “To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” “Maintain” or “restore” are more appropriate words to use than “address”. The Time Horizon should only be “Real-time Operations”. “Ensure” in Measure M1 should also be replaced with the word selected to be used in R1. Regarding Requirement R3, Time Horizons should only be “Real-time Operations”. The 30 minute requirement in Requirement R13 is too restrictive and is inconsistent with EOP-008 which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore Real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall perform a Real-time Assessment at least once every two hours. • Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform Real-time assessments within two hours. Requirement R7 has removed an important concept of TOP-001-1a Requirement R6. A supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, a supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency as not take the same voltage reduction action first. Simply stating, ‘… has implemented its Emergency procedures,’ is not specific. TOP-001-1a Requirement R6 reads: R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Recommend the following change to R7 to target the TOP’s requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator’s region, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] In Part

10.2 the phrase '… as necessary by the TOP' is unclear. What TOP? Part 10.2 should be revised to be consistent with Part 10.1 and read: 10.2. Outside its Transmission Operator Area: Sub-parts 10.1.3 and 10.2.3 should be made consistent. "Ensure" remains in the posted requirement R13. Suggested rewording R13: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The "s" in system should be capitalized in Requirement R15. R3, M3, M4, R5, M5, M6 all use the words to comply with operating instructions, but R4 and R6 use the words perform an operating instruction. The wording should be consistent. Measure M7 should be corrected to be written like M3 and M5 in the past tense: "…unless such assistance could not be physically implemented…" Measure M8 should be revised since R8, and the first part of M8 refer to operations "that result in, or could result in, an Emergency". Therefore, the last sentence in M8 should read: "If no such situations have occurred, the TOP may provide an attestation." Requirement R11 directs the Balancing Authority to "…monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load…". Monitoring Special Protection Systems is not a function of the Balancing Authority. Requirement R11 can be removed. Should M11 use the same examples of evidence as does M10, for example Energy Management System description documents? M12 should have a broader scope. If the auditor is to verify that the TOP did not operate outside IROL for a duration exceeding IROL TV, then the TOP should provide information on all occasions in which he operated outside IROL for any period of time. This would reflect the RSAW's audit approach. M12 should read: "Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL Tv. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred." For IROLs there is a maximum exceedance duration specified, but for SOLs in R14/M14 there is no leeway. Thus if a SOL is exceeded for 30 seconds, the TOP must have evidence it initiated its Operating Plan. This applies also for the VSL in the Table of Compliance Elements. No difference is made if the TOP initiates its Plan within the minute or after half an hour. Entities generally have very many SOL exceedances a year and to document each of them a proof of Implementation of a Plan is unrealistic. Whereas IROLs may be more severe than SOLs, the measure is less stringent. In the C. Compliance section, under 1.3 Data Retention, Measure M14 is mentioned in the second and third paragraphs giving it two different data retention periods. There is a typing error in the fourth paragraph referring to R13/M13: "Each TOP shall each keep data (…)". Remove the second "each". In the Table of Compliance Elements there is a typing error in the last paragraph for Severe VSL listing for R8: "or more than 15%". For R9, replace "and" with "or" because generally only one of the elements will be outaged. The VSLs should be revised to read "…sustained outage of telemetering or control equipment, or monitoring or assessment capabilities, or associated communication channels." R10 and R11 should have similar VSLs. Presently if the TOP does not monitor a facility, it will be a Moderate VSL but if the BA does not monitor a facility, it is a severe VSL. Everything is lumped together for the BA whereas in reality it is not an all or nothing situation. R11 should therefore have VSLs equivalent to those in R10. R14 should have different VSLs depending on the time it took the TOP to initiate its Operating Plan. R15 should have different VSLs depending on the time it took the TOP to inform its RC. Requirement R15 appears to be past tense, ' inform.. RC of actions taken…'. So one would believe that a pre-call is not required before actions are taken by the TOP. What is the purpose of this requirement? What is the added value in informing the RC after the fact of the actions that were taken to mitigate SOL exceedances? The TOP should be obligated to notify the RC if it cannot manage the exceedance on its own and needs assistance (another requirement). However, notifications via SCADA should be sufficient to address the concern. M15 – This measure does not include multi-modal communications. The TOP should be able to take credit for telemetered information (breaker operations) that communicates to the RC actions that have been taken. Also there is no time component for when to report. For example during, 5 minutes after, a day after. The word "own" should not be deleted from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. The new requirement R19 addresses the data exchange capabilities needed. If non-BES facilities are to be included anywhere in the standard, they should be included in the BES by exception, especially since they are contributing to a SOL exceedance. R19 and R20 seem redundant with R10 and R11 since in R10 and R11 the TOP and BA are monitoring reliability required data, and they must have the data exchange

capabilities. Also, TOP-003-3 requires the TOP to develop data specifications to support Real-time monitoring and operation of the BES, and negotiate with data supplying entities the format, period and security protocol of the data exchange. This implies the requirement of a data exchange capability. We suggest removing R19 and R20. What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility in, let's say in Transmission Operator Area "A", which is not electrically "adjacent" to Transmission Operator Area "B", impacts Transmission Operator Area "B".
Individual
Muhammed Ali
Hydro One
No
Requirement R10 presents a significant concern. A Transmission Operator cannot be held responsible for monitoring in a neighboring Transmission Operator Area; a Transmission Operator can only rely on data provided by a neighboring area. If a Transmission Operator was responsible for monitoring in a neighboring area, what is the TOP monitoring, how, what are the available actions and obligations, should the actions be taken unilaterally?
Individual
Thomas Lyons
Owensboro Municipal Utilities
No
The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI. Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: "Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area." In R10, replace "necessary" with "applicable" to maintain consistency with the definitions of Real-Time Assessment and Operational Planning Analysis. Suggested Wording: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary applicable by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area In R13, the OC Review Group suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In the R13 VSL, the OC Review Group suggests the time graduations for each level of VSL be retained (30-35 minutes, 30-40 minutes, 40-45 minutes, >45 minutes). In R18, the OC Review Group suggests removing the word "always" before "operate" and provide graduated VSL to allow for when limits were determined to be incorrect due to mistake in entry of data. Suggested Wording: "R18: Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs." Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?
Group
BC Hydro
Patricia Robertson
No

BC Hydro’s concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of “Operating Instructions” broadens to non-emergency situations. Requirement R3 and R4 have the BA’s complying with TOP’s Operating Instructions. BC Hydro’s concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no “out” clause based on reliability conflicts – such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an “out” clause.
Group
PacifiCorp
Sandra Shaffer
No
Definition of Real-Time Assessment contains provisions that will make compliance with the Requirements unattainable. First, the applicable inputs to the assessment include among other things, “known Protection System status or degradation.” Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation.
Individual
Roger Dufresne
Hydro-Quebec Production
No
Inclusion of NON-BES at R10 is inacceptable
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
I continue to disagree with the level of detail in M3 and M4 for entities on the receiving end of a recorded instruction at the Transmission Operator/Balancing Authority level. Why should this have to be auditably demonstrated at both ends when everything is recorded upstream?
Individual
David Jendras
Ameren
No
We have concerns on what constitutes "Operating Instructions", and over how an entity is supposed to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up TOP's to an very burdensome way of documenting compliance. We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. Over the years the industry has clearly learned what a “Reliability Directive” means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able locate any such information in the Reliability Standard itself, nor does the standard give guidance on when there are no BES events for the period being audited.
Individual
Andrew Z. Pusztai

American Transmission Company, LLC
Yes
ATC agrees with the changes to the proposed TOP-001-3, however, ATC recommends that Requirement R9 be modified by replacing “sustained” with “planned or sustained.” This modification will provide clarity to the requirement and align with comments made by the SDT during the October 16th TOP/IRO webinar that planned outages were in view.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Group
Bureau of Reclamation
Erika Doot
No
First, Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3 R1–R6 and the entire TOP/IRO Revisions. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators. During normal operations, Reclamation does not believe that Transmission Operators should be able to always issue mandatory Operating Instructions to generators that may damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers). Reclamation disagrees with the drafting team's assertion that "the definition for Reliability Directive is not needed due to work … on the definition of Operating Instruction." Reclamation believes that additional conversations with FERC may be necessary, and that TOP-001-3 should maintain the important concept that Balancing Authority and Transmission Operators only may issue Reliability Directives to address Emergencies or avoid Adverse Reliability Impacts. Reclamation also believes that Balancing Authories and Transmission Providers should be required to inform entities when they are issuing a Reliability Directive. In some instances, Balancing Authorities and Transmission Providers have decided after the fact that an instruction was a Reliability Directive. Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked if an entity does not describe the instruction as a Reliability Directive. Second, Reclamation also continues to disagree with the drafting team's proposal to revise TOP-003-3 to require Generator Owners, Generator Operators, and Transmission Owners to meet any data specification outlined by Transmission Operators or Balancing Authorities. Like TOP-003-1, TOP-003-3 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage, a requirement that has existed for 7 years. Reclamation does not support TOP-003-3 because it does not clearly define what types of data entities can request or may be required to provide, and will create significant operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas. As an example, Reclamation owns and operates over 50 hydroelectric facilities in seven control areas and this change would prevent Reclamation from adopting a uniform approach to demonstrating compliance with TOP-003. Under the current version of TOP-003, Reclamation can present a uniform approach to demonstrating that it submits planned outages before noon the day before the outage. In fact, like many generation entities, Reclamation generally submits planned outages more than a year in advance and plans non-routine outages as far in advance as practical. Under the proposed version of TOP-003-3, Reclamation would have to track and adjust individual generator Standard Operating Procedures (SOPs) to meet different and perhaps ever changing data specifications developed by each Transmission Operators, which could result in high costs for little reliability benefit.
Individual
Brett Holland
Kansas City Power and Light
Individual
Robert Fox on Behalf of David Austin
NIPSCO

No
NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001. NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
Group
Con Edison, Inc.
Kelly Dash
No
Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours. Requirement R7 raises jurisdictional concerns. We recommend the following change to R7 to target the TOP's requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator's region, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Individual
Diane Barney
New York State Department of Public Service
No
The requirement to monitor non-bulk facilities raises jurisdictional questions which needs to be settled before inclusion.
Group
MRO NERC Standards Review Forum
Joe DePoorter
No
R1 and R2 are ALL encompassing actions that cover every actionable NERC Requirement that the TOP and BA must accomplish. As written, "Each (BA, TOP) shall act to address the reliability of its (BA, TOP) Area via direct actions or by issuing Operating Instructions". EOP-002-3.1, R6, IRO-001-1.1, R8, are two examples where there must be "immediate" actions by the BA or TOP. If "via direct actions" is maintained in this proposed Standard, there will be a non-compliance double jeopardy impact if the BA or TOP violates an "immediate action" Requirement. Is the intent of R1 and R2 to issue Operating Instructions when the BA or TOP cannot maintain a reliability of their associated area? The NSRF wishes to points out that the Standards Process Manual section 2.4 describes a "Results Based Requirement" as "Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective and not how that objective is achieved". R1 & R2 with their broad, general language do not meet the threshold for a "Results Based Requirement". The NSRF agrees with issuing Operating Instructions when required to maintain your system in a reliable state. But the all-encompassing "via direct actions", is applicable to over 460 Requirements that a BA must comply with. How is this going to be measured for the BA (or TOP)? Are voltage schedules going to be measured when that is covered in the VAR Standards? Is seems to be a catch all Requirement. A possible rewrite of R1 and R2 could read: "Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance ". M1 does not reflect the current language of the rewritten R1. The word "ensure" still resides in M1. R9. Concerning "sustained outages", is there a minimum reporting threshold for this undefined term? EOP-004-2, Event Type "Complete loss of voice communication capability" and "Complete loss of monitoring capability" has a 30 minute continuous threshold. The NSRF recommends using the same bright line criteria of EOP-004-2 as stated above.

R13. Real-time Assessment: The NSRF still has concerns about how entities will incorporate "protection system status" into their real-time 30 minute assessment to be fully compliant. More clarity is needed for entities to verify that they have met the requirement. How are entities expected to show that their operators are aware of protection system status (as defined in the proposed Real-Time Assessment definition) and understand the system impact if a protection system is out-of-service? If policies, procedures, and snapshots of system operator tools are sufficient, this can be done. However, large scale state estimator real-time contingency assessments used have limitations. State estimators run DC powerflows based on programed line and node based contingencies. Protection system status changes that modify the lines and nodes studied may not be easily incorporated into state estimator systems in 30 minutes. Protection system coverage could easily change for known and unknown conditions. Known changes can include PRC testing. The PRC testing standards have mandated large amounts of testing for even moderately sized system so that daily testing must occur to meet mandatory testing timeframes. The large volume of PRC testing could make accounting for all protection system status changes within 30 minutes difficult to verify and puts entities at risk for maintaining perfect compliance to a large number of requirements since many of the TOP / IROL standards include the real-time assessment definition. Recommend that "protection system status" be deleted from the definition or at a minimum clarify that protection system status consideration by system operations is acceptable to be compliant, since "status consideration" equates to "situational awareness". As written in R13: R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] M13.Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence. With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall "ensure that a Real-time Assessment is performed at least once every 30 minutes;" however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP." Measure M13 would need commensurate edits to conform with this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the "situational awareness" because they will not know "known Protection System and Special Protection System status or degradation…" per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words "have situational awareness" in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. Please review the below violation which is based on Auditor notes (for TOP-002-2, R11). This shows that simple "situational awareness" is predicated on "system analysis", which the NSRF looks at as the entities RTCA. A second concern with the TOP-001-3 definition of Real time assessment, the recent TOP-002-2.1b R11 auditor guidance in the new RSAW, and a recent TOP-002-2.1b R11 violation cited below, is the proposed requirement is not technically feasible today. The three items listed just above in conjunction require an on-line dynamic stability assessment tool that can run multiple AC dynamic angular and voltage stability assessments in less than 30 minutes considering EMS input of the most recent alarm, SPS, and degraded state alarm statuses. The NSRF isn't aware of RTCA technology that can meet these requirements. Alternately, the assessment falls to human

manpower to perform these studies. Entities must identify a RTO, RC, or PA with staff available 24/7 to perform this or train its own 24/7 staff. It takes time to train dynamic stability staff and time to change the model to capture “known Protection System” statuses. TOP-001-3 Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) TOP-002-2.1b violation: (note this is publically posted in the most recent November compliance and enforcement spreadsheet) TOP-002-2.1b R11. On two occasions, SCS-Trans’ updated Bulk Electric System (BES) studies failed to reflect current system conditions. Specifically, two unscheduled outages of Protection System components, one for a 500 kV transmission line and one for a 230 kV transmission line, were not considered in SCS-Trans’ operating studies. TOP-002-2.1b RSAW auditor Guidance: Evaluation of Protection System Outages Protection Systems must operate and clear faults within the required clearing time to satisfy system performance requirements. All outages of Protection Systems or their components that affect the reliability performance of the transmission system must be evaluated for the periods they are scheduled, in the planning horizon in TPL assessments and in the operational planning timeframe through operating studies. For example, if a transmission line has A and B protection packages that are not functionally equivalent and the outage of one protection package affects the operating speed of the Protection System, the impact of slower fault clearing on the power delivery capability of the Bulk Power System (BPS) must be considered in the assessments and studies. Such impacts also must be considered when a transmission line has a single protection package and one component of the package (e.g., the communication system) is taken out of service
Group
Oklahoma Gas & Electric
Terri Pyle
No
M1 – Replace ‘ensure’ with ‘address’ as in the requirement. R8 – With the removal of ‘other’ when referring to ‘known impacted Transmission Operators’ an overzealous auditor could require a Transmission Operator experiencing a condition which could be an Emergency or result in an Emergency would have to inform itself. Using ‘other known impacted Transmission Operators’ eliminates this situation. We recommend the drafting team return ‘other’, in the suggested location, to the requirement, measure and VSLs. R8 VSLs – If the drafting team decides not to make this suggested change, the term ‘other’ needs to be removed from the first ‘OR’ in the Severe VSL. In the last ‘OR’ of the Severe VSL insert the phrase ‘…, whichever is greater,…’ between ‘Authorities’ and ‘of’. R9 – We appreciate the drafting team attempting to add specificity to Requirement R9; however, ‘sustained’ is undefined. How does a Transmission Operator determine whether or not they are compliant with this requirement? What ensures auditors will consistently apply the terminology. We recommend the drafting team incorporate language consistent with COM-001-2, R10 which requires notification for outages lasting 30 minutes or more. If 30 minutes is determined to be too long, reduce the time to 15 minutes. We would like to suggest adding the term ‘known’ in front of ‘impacted’ in the second line of Requirement R9. We would like for the drafting team to help provide some clarity in Requirement R9….. does it apply to Planned Outages? Also, we noticed that the term ‘planned’ was removed from Measurement M9. Our question to the drafting team was this your intent to remove this term and if so would you provide clarity on why the term should be removed. We would like to suggest that the drafting team tie Requirement R9 to the Data Specifications of TOP-003-3 as suggested in the Mapping Document. Also, we would like to thank the drafting team for their willingness to adjust to many suggestions that are submitted and we truly appreciative for all or your time and efforts. R9 VSLs – Delete the phrase ‘NERC registered’ and insert the phrase ‘…, whichever is greater,…’ between ‘entities’ and ‘of’ in the ‘OR’ of the Severe VSL. R10 VSL – The drafting team should consider adding a 2nd ‘OR’ to the High VSL which states ‘The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and one of the items listed in Requirement R10, Part 10.2.’ R16 – We would like for the drafting team to provide more clarity on the word “telecommunication”. The word “telecommunication” should apply only to specific

outages or maintenance work done on the SCADA/EMS that affect the System Operators. R19 & R20 Moderate and High VSLs – Replace ‘entity’ with ‘entities’.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration L.P. (“ICLP”) understands that FERC has ordered that TOPs and RCs must be able to monitor “non-BES” systems that they determine will affect System Operating Limits. However, it naturally follows that such important facilities must be part of the BES – and addressed in a far more formal way. It seems to ICLP that just such an exception process was created in NERC’s Rules of Procedure when the Definition of the BES was modified. It allows the TOP/RC to make the case for the new addition – while the owner/operator has the opportunity to challenge it. Even if there needs to be an emergency bypass procedure to account for unexpected circumstances, at least a level of important control will exist. Otherwise, components and facilities can be essentially added to the BES without any recourse on the part of the affected entity. This raises the specter of the improper sharing of proprietary information and the chance of economic discrimination if such authority is misused. Secondly, a GOP will be expected to capture the fact that every Operating Instruction was performed unless it would “violate safety, equipment, regulatory, or statutory requirements.” ICLP will execute in good faith to every instruction, but we are not confident that our log entries will be up to auditor expectations – particularly if routine status or some other low-impact action is requested. The alternative offered by the project team (the RSAW only directs CEAs to review logs where a EOP-004-2 defined Event took place) is not binding. It is not hard to see that expectations will vary by Regional Entity and even change over time. Furthermore, the target of Operating Instructions will not be limited to BES Facilities. This could mean that as a Cogeneration Facility, we will be put into an untenable bind if ordered by a BA or TOP to re-direct capacity to the BES at the expense of our internal customer. Of course we are responsive to the needs of the greater system, but it should not be up to external entities to decide which needs take priority – keeping in mind that our installation is a critical part of the national chemical infrastructure.
Group
Tennessee Valley Authority
Dennis Chastain
No
TVA feels that requiring a TOP to monitor neighboring facilities that are non-BES to determine SOL violations should not be required (see R10., 10.2.3). If non-BES facilities are required for the reliable operation of the transmission system they should first be included into the BES by use of the Rules of Procedure exceptions process.
Individual
Thomas Foltz
American Electric Power
Yes
Individual
Denise M. Lietz
Puget Sound Energy
No
The drafting team’s revisions significantly improve the proposed standard. However, requirements R3 and R5 continue to impose a high compliance burden on entities that receive Operating Instructions. For example, a Generator Operator could receive thousands of dispatch instructions each year. As the term is defined, each of these dispatch instructions would be an Operating Instruction and the GOP would be required to demonstrate that it complied with each of these Operating Instructions (or that it was unable to comply for the reasons specified in requirements R4 and R6). The standards drafting team for COM-002 recognized this issue when it developed a tiered approach for the communication protocols associated with Operating Instructions. The first tier requires an entity to periodically monitor compliance with its communications protocols and then

correct issues that are discovered during this monitoring. The second tier requires entities to comply fully with its communication protocols during Emergency conditions only. This approach recognizes the importance of formal communications during both normal and Emergency conditions, but appropriately minimizes the compliance burden that would be associated with demonstrating compliance with an entity's communication protocols for all Operating Instructions. The drafting team should model that approach in this standard.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
There was the addition of "sustained" for clarification in requirement R9. Tri-State wonders if the SDT meant to use the defined term "Sustained Outage" in this requirement or if they did not intend to use that defined term?
Group
Seattle City Light
Paul Haase
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst abstains and offers the following comment for consideration. 1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define it when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator..." R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority."
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Thank you SDT members for all of your work, the following were our comments on the proposed standard language. We will be voting affirmative, but think comments below crucial the final modifications to the standard. 1. "Ensure" was removed from R1 and R2 but please also remove it from M1 and M2. 2. R3 – LSE needs to be removed as this function is soon to be retired. 3. With the new definition of RAS just voted on, it would be best to replace RAS with SPS as "SPS" is going away. 4. Please change "maintain" to address in R19/M19 and R20/M20. This has similar implications of "ensure." Of course we should do all in our power to maintain and ensure the bulk electric system, but there will be situations (no matter how many standards are in place) where industry may not be able to ensure or maintain reliability. To use such language is putting an unrealistic expectation in place that gives the regulator the ability to use our own words to find fault, even when no fault is present.

Individual
Leonard Kula
Independent Electricity System Operator
No
We generally agree with the changes made to the proposed TOP-001-3 standard, but continue to have a serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We strongly believe that the Requirement R4 of TOP-004-2 addresses a critical reliability aspect that ensures the bulk electric system is operated in a reliable manner during real-time operations. And, if is not actually replaced by any new or revised requirement in TOP-001-3, it will create a reliability gap that is critical to the reliable operation of the bulk electric system. Requirement R4 of TOP-004-2 stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. In previous postings, we expressed a concern that by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be required to reconfirm or reestablish valid SOLs or IROLs when entering an unknown (or unstudied) state. We recognize that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. The SDT thus argues that this, together with the TOP-001-3 Requirements R12, R13, and R14, will allow the operators sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System and hence Requirement R4 of TOP-004-2 can be retired. We continue to disagree with the SDT’s rationale for retiring R4 of TOP-001-3. Below is our point by point comment on the SDT’s response to our last round of comment. This is not meant to be a criticism of the SDT’s response. Rather, we choose to present our comment in this manner so that we can more clearly present our view on each of the technical arguments that the SDT made. a. The SDT [believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv.] The IESO believes that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and therefore there does not exist an updated, valid limit until it is re-determined (or reconfirmed). We further believe that the SDT’s view that “by complying with the proposed requirement, an entity will never enter into an unknown state” may be an oversimplified assumption, if not an oversight. An unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover. b. [The premise of the SDT’s philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13.] The IESO believes that the OPA and RTA are good tolls, but they only look ahead at anticipated conditions and assess real-time situation in response to system changes and by themselves they are not a limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, such limits may not exist; and OPA and RTA are not the tasks to calculate limits for the anticipated or prevailing conditions, especially for the stability restricted SOLs/IROLs. c. [Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT’s belief that once these limits have been established that it does not matter what event occurs to cause an exceedance.] The IESO believes that this may be true for facility limited SOLs/IROLs, but not for voltage and/or stability restricted SOLs/IROLs. d. [The event takes place and is analyzed against the set of limits currently in place.] The IESO believes that a set of valid limit (voltage and stability limited type) may not exist for conditions that have not been studied and therefore there is no such “set of limits currently in place”. e. [It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14.] This is achievable if the limits already exist. But when the limits do not exist, as in the case of SOLs or IROLs that are restricted by stability and when the prevailing conditions are ones that have not been studied before, there is not a target (SOL or IROL) with which the system is to be restored to. f.

[Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. The IESO believes that an Operating Plan is only a plan for the anticipated conditions. Changes during real-time operation can render the assumptions and pre-determined limits invalid and hence the responsible entity cannot rely on the Operating Plan to provide SOLs/IROLs that are stability restricted. We agree that with the current technology, it is doubtful if any entities can rely on real-time tools to calculate SOLs/IROLs in 30 minutes. However, this should not be a reason to not reestablish SOLs/IROLs when an entity encounters a condition that is “unknown” or not studied before. There are various means to achieve such tasks, but a necessary first step to ensure entities reestablish valid SOLs/IROLs is to stipulate this in a standard. Retiring R4 of TOP-004-2 will do just the opposite: responsible entities will not be mandated to reestablish valid limits to begin with when entering an unstudied or unknown state. We once again urge the SDT to reinsert R4 of TOP-004-2 to TOP-001-3, or to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in SOL calculations.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
Per my previous comments, I continue to object to the auditing requirements in M3 that the receiving LSE/DP entity demonstrate receiving a communication, when the communication is recorded at the BA/TOP level.
Individual
Rich Salgo
NV Energy
No
The comments of NV Energy, particluarly with regard to requirement R13, remain unaddressed in this latest posting. We continue to urge the SDT to depart from the zero defect approach on the language of R13. It seems unreasonable to expect perfect execution of the suggested real-time analyses, including the provisions for incorporation of the elements of SPS/RAS and protection system status,17,520 times per year. By the SDT's own response to NV Energy's comments in the prior ballot/comment period " This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times." Yet the SDT nevertheless declined to make any change to the language of R13. We continue to believe that the language suggested below is reasonable given the complexity of the requirements of TOP-001-3. We therefore suggest the following: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.”
Individual
Joshua Smith
Oncor Electric Delivery LLC
No
Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor’s suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States: R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator: 10.2.1. Facilities, 10.2.2. Status of

Special Protection Systems, and 10.2.3. Non-BES facilities. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R1O.2, R10.2.1., R10.2.2 and R10.2.3 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.
Individual
Jason Snodgrass
Georgia Transmission Corporation
No
(1) GTC requests the drafting team remove the DP and LSE designation from Requirements R3 and R5 and develop separate requirements for the DP and LSE to comply with Operating Instructions to shed or shift load. By making this change, the requirements could be made clearer that the Operating Instructions that the DP and LSE receive from the TOP with respect to the defined term Operating Instruction, correspond to "impacting" the output of an Element of the BES (shed or shift load). Because the term Operating Instruction is tied to the BES, a standalone requirement is necessary to eliminate the ambiguity associated with entities with multiple registrations such as TOs who are also DP/LSE's that own BES equipment. It should be noted that this Standard does not apply to a Transmission Owner, but the field personnel who perform switching in substations of entities with both registration types are typically the same personnel. The level of Operating Instructions performed for multiple registration type (TO/DP/LSE) entities would be much more voluminous and burdensome due to the ownership of transmission equipment than the typical DP/LSE type entities for the same requirement. GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP/LSE dispatch center that does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). GTC urges the drafting team to consider this additional exposure of field personnel of TO/DP entities that switch in transmission substations to which the standard does not apply. Per discussions with Standard Drafting Team members and industry personnel, the scenario for DP/LSE's to receive Operating Instructions are limited to load shed or shift scenarios to preserve the reliability of the BES by the defined term associated with "impacting" the output of an Element of the BES. Exposing these multiple registration type entities to a set of mandatory standard requirements to which they do not apply such as those TOs and DPs identified above, demonstrates the potential flaw with the current language. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: • Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator to shed or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. • Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority to shed load or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) Please note that M1 should be changed from "ensure" to "address" to match R1. (3) Part 10.1.3 and 10.2.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. Refer to NERC's memo dated April 10, 2012 with respect to use of the term BES in Reliability Standards. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. Although the TOP will monitor Non-BES facilities in practice, there is no reason to include non-BES Elements in the requirement subject to mandatory enforcement. Parts 10.1.3 and 10.2.3 that reference "non-BES facilities" should be struck.

Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
Yes
Group
JEA
Tom McElhinney
No
For R4&5 the timing is vague. Should it be done immediately, within 30 minutes, etc. For R9 we are concerned that "sustained" is vague. If it lasted 2 minutes, was that a sustained outage? R10 should only include BES elements. Items of concern can be added through the inclusion process. R13 should have an exclusion that allows procedures to be implemented when system information is unavailable to reduce the risk instead of simply requiring real-time assessments be performed at least every 30 minutes. Even having a complete redundant EMS system might not prove sufficient to prevent a violation. R19 & 20 should require other BAs and TOPs to participate.
Group
Duke Energy
Michael Lowman
No
General Comments: Duke Energy is concerned with the uncertainty surrounding the inclusion and/or exclusion of Load Serving Entity in various Standards Projects. This inconsistency among Standard Drafting Teams creates uncertainty in the industry as to the expectations of the LSE, or whether the LSE will even be a applicable function. A more consistent application of the LSE function in proposed NERC standards is needed. R1: Based upon the comments provided below, Duke Energy suggests that R1 be focused on the TOP issuing Operating Instructions and suggests the following revision to R1 for clarity: “Each Transmission Operator shall issue Operating Instructions, as necessary, to maintain the reliability of its Transmission Operator Area”. We believe the intent is for the TOP to “maintain” the reliability of the TOP Area by Issuing Operating Instructions. Duke Energy believes that by using the term “address” in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term “maintain”, the standard would require the entity to identify the problem and maintain the reliability of its TOP Area. Lastly, Duke Energy has concerns with the use of the term “act” in R1 and R2. As currently worded, absent the TOP issuing an Operating Instruction, R1 states that the TOP shall “act”, in other words, do its job. If an entity fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other TOP standard, it could be argued that the entity failed to perform a certain “act”, which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase “issue Operating Instructions” eliminates the possibility of a double jeopardy situation. R2: Based upon the comments provided below, Duke Energy suggests that R2 be focused on the BA issuing Operating Instructions and suggests the following revision to R2 for clarity: “Each Balancing Authority shall issue Operating Instructions, as necessary, to maintain the reliability of its Balancing Authority Area”. We believe the intent is for the BA to maintain the reliability of its BA Area by Issuing Operating Instructions. Duke Energy believes that by using the term “address” in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term “maintain”, the standard would require the entity to identify the problem and maintain the reliability of its BA Area. Lastly, Duke Energy has concerns with the use of the term “act” in R1 and R2. As currently worded, absent the BA issuing an Operating Instruction, R2 states that the BA shall “act”, in other words, do its job. If the BA fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other BA standard, it could be argued that the entity failed to perform a certain “act”, which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase “issue Operating Instructions” eliminates the

possibility of a double jeopardy situation. R9: Duke Energy would like the SDT to clarify the time duration of a “sustained outage”. It is unclear if an outage lasting longer than 10min, 20min, 30min, etc. would be considered a sustained outage. Was it the SDT’s intent to allow entities the flexibility to define what constitutes a “sustained outage”? SOL Exceedance document: (1) Duke Energy suggests replacing “Thermal Limit Exceeded” with “SOL Limit Exceeded” to provide clarity in the example given in Table 1. (2) Duke Energy does not believe that the System Operating Limit Definition and Exceedance Clarification document should be attached to the TOP-001-1 standard. Instead, we believe it should be a standalone guidance document for the industry. If this were to occur, Duke Energy would likely vote “Affirmative” for TOP-001-1 as written.
Group
DTE Electric Co.
Kathleen Black
Yes
We support the changes and have no concerns/comments to add.
Individual
Daniel Duff
Liberty Electric Power
No
The standard does not contain a requirement for the TO to identify the Operating Instruction as a reliablity instruction as opposed to a market instruction.
Individual
Jo-Anne Ross
Manitoba Hydro
No
Manitoba Hydro agrees with changing the term “ensure” to “address” throughout the standard, however in M1 the term “ensure” remains even though its associated requirement R1 has “address”. We believe the intent was to replace “ensure” with “address” as it is in M2. In Pages 15 and 16 of TOP-001-3, Table of Compliance Elements, “Operations Planning” in the Time Horizon column of R1 through R6 should be deleted because they were deleted in Requirements R1 through R6.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
For smaller entities that do not own or operate a state estimator, the Real-time Assessment required in R13 would be overly burdensome, if not impossible, to meet internally. Although the drafting team indicates a third-party service may be utilized in lieu of an internal system, smaller entities would be wholly reliant on a third-party in order to maintain compliance with R13. This is of particular concern when considering that if a Protection System status were to change unexpectedly on a smaller entity's system, that entity would be expected to notify a third-party and then have that third-party perform a modified contingency analysis, pending availability, all within 30 minutes. Rather than treat all TOPs the same without consideration for size or risk to the BES, recommend that, at a minimum, the timeframe for conducting the Real-time Assessments be expanded or else allow the individual TOPs to establish the timeframe.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Yes
Individual
John Brockhan

CenterPoint Energy Houston Electric LLC
No
R1. – CenterPoint Energy agrees with the addition of "…direct actions or by issuing Operating Instructions" as well as using 'address' rather than 'ensure', however CenterPoint Energy prefers the manner in which the previous R1 was drafted. CenterPoint Energy suggests the following language: "Each Transmission Operator shall take direct actions or issue Operating Instructions to address the reliability of its Transmission Operator Area." R10.2 – CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically "neighboring Transmission Operator Areas". CenterPoint Energy agrees with the Functional Model that it is the Reliability Coordinator's responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy's reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP's view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. – CenterPoint Energy agrees that a Real-Time Assessment (RTA) should be run every 30 minutes, however the Company is concerned that events could occur that are outside of the Transmission Operator's control (Ex. Loss of ICCP data) that may prevent the Transmission Operator from performing a RTA as required; therefore there should be a caveat as to when exceeding the 30 minutes is allowed. CenterPoint Energy recommends the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality. R14. – CenterPoint Energy suggests changing Operating Plan to Operating Plan(s).
Individual
Scott Berry
Indiana Municipal Power Agency
No
Indiana Municipal Power Agency (IMPA) appreciates the hard work and effort the SDT has put into this standard. IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow and to keep evidence to show they performed the Operating Instruction. This seems to be going in the opposite direction of what NERC is proposing in its RAI program with the theme of concentrating on the "risk" to the BES. IMPA acknowledges that the SDT writes the standard but also understands the influence NERC has on standard drafting teams. During high load times, an entity that has to follow its TOP's Operating Instructions will need to keep a good recording or log entry of the Operating Instruction and then proceed to keep documentation showing it was performed. Since the definition of an Operating Instruction is vague and not clear, an entity will have to do this for every instruction from its TOP regardless of how they see the instruction because an auditor may view it as an Operating Instruction. For example, a Generator Operator will have to keep a log and evidence to show it performed the Operating Instruction for every start, stop, and load command for all of its generating units within its fleet (PJM is the TOP for many GOPs). IMPA recommends the drafting of requirements that allow entities to focus on the "risk" to the BES and not write requirements which are administrative in nature (meet paragraph 81 criteria).
Group
ISO/RTO Council Standards Review Committee (SRC)
Greg Campoli
No
SRC members generally agrees with the modifications to TOP-001-3 with the following additional recommendations for clarity, consistency, and/or to eliminate redundancy: 1. In Requirement R1, it is recommended that "address" is ambiguous and should be revised to "maintain" or "preserve" and that "[V]ia direct actions or by issuing Operating Instructions" should be revised to state "by initiating direct actions or issuing Operating Instructions." Also, the measure M1 should be revised for consistency. 2. Review of modifications to IRO-001-4, Requirements R1, R2, and R3 to ensure consistency with the proposed revisions to TOP-001-3, Requirements R1 – R6. 3. Requirement R7

has not retained an important concept contained within the previous requirement (TOP-001-1a – R6), which is that a supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, the supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency has not taken the same voltage reduction action first. Hence, the phrase '… has implemented its Emergency procedures,' is less specific than the previous standard and should be revised to provide '… has implemented its comparable Emergency procedures.' 4. Requirement 10 seems duplicative in function with IRO-003, which requires the RC to monitor facilities associated with System Operating Limits (SOLs) and represents an overlap of the RC's responsibility with the TOP draft requirement. Specifically, the TOP would have a requirement to monitor facilities outside of its TOP area that could affect SOL exceedences within its TOP area when the RC is already tasked with the "wide-area" view. This is in direct conflict with the Functional Model definition of a TOP which limits TOP responsibility to assets within its area. Further, it is recommended that the term "non-BES" Be removed from Requirement R10. The "inclusion" process should capture all equipment that are sub-100 kV, but that affect BES reliability and bring this equipment into scope. Finally, in Requirement R10.2, the phrase '… as necessary by the TOP' is unclear and should be redrafted to be consistent with 10.1 "10.2. In the neighboring Transmission Operator Area." Conforming changes should also be made to Requirements R10.1.3 and 10.2.3. NOTE: this comment is not supported by PJM 5. The SRC appreciates the SDT's effort to clarify the obligations of Balancing Authorities under Requirement R11. However, it respectfully submits that "in order to be able to perform its reliability functions" may still be ambiguous, resulting in subjective determinations of compliance. Additional revision is proposed to mitigate this ambiguity and to ensure that the reliability functions being referenced are clear: "Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange-generation balance within its Balancing Authority Area, and support Interconnection frequency in real-time." 6. The SRC respectfully submits that R15 is not necessary to ensure an Adequate Level of Reliability. Specifically, since the exceedance would have already been addressed or is being actively managed by the TOP and communication would already be occurring with impacted parties pursuant to other requirements, a requirement to inform the RC isn't needed. If R15 is maintained, the SRC suggests including SCADA information in the Measurement so that the TOP can "inform" the RC through this mechanism. NOTE: this comment is not supported by PJM 7. The SRC reiterates it serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without requirements in TOP-001-3 addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unstudied state. In previous postings, the SRC expressed a concern that, by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be required to reconfirm or reestablish valid SOLs or IROLs when entering an unstudied state. We recognize that, by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, entities will always be assessing the reliability of the BES. However, we continue to disagree with this rationale and provide additional information in response to the SDT's response to our last comment. In response to the SDT's indication that it does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv, the SRC responds that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and, therefore, there does not exist an updated, valid limit until it is re-determined (or reconfirmed). Thus, if an unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover, then entities may find themselves in an unknown operating state. For example, in the Northeast, such as Quebec, Ontario and New York, SOLs/IROLs are observed to guard against transient or dynamic instability. These limits are normally developed using off-line analyses, as they cannot be determined within a short time using any on-line analysis tools available today. Predetermined reduction or judgment may need to be applied when system conditions, such as two or more critical facilities are out of service, diverge from the assumptions utilized in reliability assessment and other studies. In these circumstances, e.g., when an unstudied state is encountered, a necessary first step for the operating entities in these areas is to reconfirm or recalculate the limits that are valid and applicable for the prevailing conditions. The reconfirmed or reestablished limits will become the target to which the system must be adjusted. Given the use of off-line studies to set limits and identify complex system conditions, the SRC believes that the OPA and RTA are good tools, but caution that these tools only look ahead at anticipated conditions and

assess real-time situations in response to system changes. Accordingly, by themselves, they are not limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, where such limits may not exist, the OPA and RTA are not the tools to calculate limits for the anticipated or prevailing conditions, especially for stability restricted SOLs/IROLs. To summarize, it is possible for the system to be in an unstudied or unknown state where established limits either don't apply or limits have not yet been established. While the RTA, OPA, and established Operating Plans can be quickly and easily applied to anticipated conditions, changes during real-time operation can render the assumptions and pre-determined limits invalid and, hence, the responsible entity cannot rely on these tools should these circumstances occur. Thus, the SRC once again urges the SDT to modify TOP-001-3 to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in off-line calculations. NOTE: this comment is not supported by CAISO; ERCOT; MISO or PJM.
Individual
Jeremy Voll
BEPC
Group
ACES Standards Collaborators
Ben Engelby
No
(1) There are several issues with the draft standard of TOP-001-3. First, we disagree with the inclusion of the Load-Serving Entity (LSE) as an applicable entity. This function is being removed from the NERC Rules of Procedure and should not be included in the draft standard. TOP-001-3 already applies to the Distribution Provider (DP), so there will not be a gap in the future because LSEs are required to also be registered as DPs. We recommend removing the LSE from the applicability section for consistency with the revised NERC Rules of Procedure and to avoid a future standards project to correct this issue. In regards to timing, the NERC BOT will likely have approved removal of LSE before this is even approved in a final ballot by the ballot body. (2) Requirement R1 and Requirement R2 are problematic because they are vaguely written and could result in additional compliance burdens for a TOP or BA when there is an event. As currently written, any time that a TOP or BA has an outage there could be a violation because the entity did not address the reliability of its area. These requirements will be used in enforcement as additional fines without benefitting reliability because they do not state what actions should be taken. We also disagree with the High VRF and Severe VSL for these standards. These requirements are vague and need further refinement. (3) Requirements R3, R4, R5, and R6 should not apply to the LSE, as previously stated above. (4) Requirement R8 needs to be revised to remove the words "could result in an Emergency." There are numerous situations that "could" result in an Emergency, but do not. This language is ambiguous and immeasurable, and should be removed. (5) Requirement R9 has improved with the addition of "sustained outages" to clarify that notification is not required for momentary events. However, R9 is not clear as to the outage thresholds that would require a notification. When must the BA or TOP notify its RC? The requirement is ambiguous as written, which will lead to varying interpretations for compliance. This requirement needs to be revised to provide additional clarity when a notification to the RC is required. (6) Requirement R10 and part 10.1 are duplicative in listing "within its Transmission Operator Area." If taken as a whole, R10 states that "Each TOP shall monitor the following as necessary for determining SOL exceedances within its TOP Area: 10.1. Within its TOP Area: 10.1.1. Facilities…" This requirement needs to be revised to have proper sentence structure. (7) Part 10.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. There is no reason to include non-BES Elements in the requirement. Parts 10.1.3 and 10.2.3 that reference "non-BES facilities" should be struck. (8) Thank you for the opportunity to comment.
Group
SPP Standards Review Group
Shannon V. Mickens
No

M1 – Replace ‘ensure’ with ‘address’ as in the requirement. R8 – With the removal of ‘other’ when referring to ‘known impacted Transmission Operators’ an overzealous auditor could require a Transmission Operator experiencing a condition which could be an Emergency or result in an Emergency would have to inform itself. Using ‘other known impacted Transmission Operators’ eliminates this situation. We recommend the drafting team return ‘other’, in the suggested location, to the requirement, measure and VSLs. R8 VSLs – If the drafting team decides not to make this suggested change, the term ‘other’ needs to be removed from the first ‘OR’ in the Severe VSL. In the last ‘OR’ of the Severe VSL insert the phrase ‘…, whichever is greater,…’ between ‘Authorities’ and ‘of’. R9 – We appreciate the drafting team attempting to add specificity to Requirement R9; however, ‘sustained’ is undefined. How does a Transmission Operator determine whether or not they are compliant with this requirement? What ensures auditors will consistently apply the terminology. We recommend the drafting team incorporate language consistent with COM-001-2, R10 which requires notification for outages lasting 30 minutes or more. If 30 minutes is determined to be too long, reduce the time to 15 minutes. We would like to suggest adding the term ‘known’ in front of ‘impacted’ in the second line of Requirement R9. We would like for the drafting team to help provide some clarity in Requirement R9….. does it apply to Planned Outages? Also, we noticed that the term ‘planned’ was removed from Measurement M9. Our question to the drafting team was this your intent to remove this term and if so would you provide clarity on why the term should be removed. We would like to suggest that the drafting team tie Requirement R9 to the Data Specifications of TOP-003-3 as suggested in the Mapping Document. Also, we would like to thank the drafting team for their willingness to adjust to many suggestions that are submitted and we truly appreciative for all or your time and efforts. R9 VSLs – Delete the phrase ‘NERC registered’ and insert the phrase ‘…, whichever is greater,…’ between ‘entities’ and ‘of’ in the ‘OR’ of the Severe VSL. R10 VSL – The drafting team should consider adding a 2nd ‘OR’ to the High VSL which states ‘The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and one of the items listed in Requirement R10, Part 10.2.’ R19 & R20 Moderate and High VSLs – Replace ‘entity’ with ‘entities’.
Individual
Daniel Mason
HHWP
No
R16 states: "Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities." Organizations should be be free to designate its preferred method for approving planned outages of data equipment. This requirement imposes on all TOPs single process for data system outage approval. The requirement should be results based on not proscriptive of the method to acheive those results. This is a huge step backwards in the development of rational reliability requirements.
Group
Bonneville Power Administration
Andrea Jessup
No
BPA reiterates its comments from the previous period on TOP-001-3: BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, “… operations that result in, or could result in, an Emergency.” It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard which has the potential to conflate events that are happening with events that have a high probability of happening. BPA suggests the drafting team clearly separate these two concepts. Additionally, BPA disagrees with the change in R16 from “Real-Time Assessment” to “analysis”. This is a very broad and, in this case, undefined term. BPA believes this could lead to differences in interpretation between a TOP and an auditor. For example, R16 applies to the Operations Planning Horizon. A study engineer’s computer is part of an entity’s analysis capability for doing studies in the that horizon. Hence, as written, this

requirement could be interpreted to mean that an entity’s IT department would need to have System Operator approval prior to working on a study engineer’s computer. BPA does not believe that was the drafting team’s intent, but this broad language does leave that possible interpretation open.

Consideration of Comments

Project 2014-03 Revisions to TOP and IRO Standards

The Project 2014-03 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 30-day public comment period from October 10, 2014 through November 10, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 133 different people from approximately 100 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

The SDT has made the following changes due to industry comments:

- Requirement R1 – removed the 'direct action' language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced 'address' with 'maintain'.
- Requirement R2 - removed the 'direct action' language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced 'address' with 'maintain'.
- Requirements R3, R4, R5, and R6 – removed the Load-Serving Entity as an applicable entity following the recent Board of Trustees (Board) action on removing Load-Serving Entity as a functional entity. (Note – Load-Serving Entity was not removed from proposed IRO-010-2 or proposed TOP-003-3 as those standards have already been approved by industry and adopted by the Board. Load-Serving Entity will be removed from those standards when the overarching project to remove Load-Serving Entity is initiated.)
- Requirement R7 – Added the phrases 'within its Reliability Coordinator Area' (as Transmission Operators will only be expected to react to requests from other Transmission Operators within the Reliability Coordinator Area and any assistance for Transmission Operator Areas outside the Reliability Coordinator Area will be done through requests from the Reliability Coordinators) and 'comparable' assistance (to assure that a Transmission Operator isn't asked to do go further than the requesting Transmission Operator has done).
- Requirement R9 – added 'known' as a qualifier for impacted entities; clarified that the requirement is for all outages by adding 'planned and unplanned' as qualifiers to outages; replaced 'sustained' by '30 minutes or more' to achieve clarity and consistency with other standards.
- Requirement R10 – deleted the phrase 'non-BES' as any need for non-BES data will be defined in the Reliability Coordinator SOL methodology and included in BES as part of BES Exception Process as necessary; clarified that an entity does not have to 'monitor' outside of its Transmission Operator Area – it only needs to utilize necessary data.

- Requirement R11 – replaced the phrase 'perform its reliability functions' with more specific language – 'maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency'.
- Requirement R15 – capitalized 'System'
- Requirement R16 – made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Requirement R17 - made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Made commensurate changes in matching Measures and cleaned up language in Measures M8 and M12.
- Made commensurate changes to VSL language and changed the VSL for Requirement R11 from binary to incremental.
- Added language to the SOL Exceedance White Paper explaining that the Reliability Coordinator's SOL methodology will specify requirements to include any non-BES data or external data in order for a Transmission Operator to determine SOLs in accordance with the Reliability Coordinator's SOL methodology.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

				1	2	3	4	5	6	7	8	9	10
2.	Group	Patricia Robertson	BC Hydro	X	X	X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat G. Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5

				1	2	3	4	5	6	7	8	9	10
3.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

				1	2	3	4	5	6	7	8	9	10
4.	Group	Erika Doot	Bureau of Reclamation	X				X					

N/A

				1	2	3	4	5	6	7	8	9	10
5.	Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Bedder	Orange & Rockland Utilities	NPCC	NA

				1	2	3	4	5	6	7	8	9	10
6.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	Oklahoma Gas & Electric	SPP	1
2.	Don Hargrove	Oklahoma Gas & Electric	SPP	3
3.	Leo Staples	Oklahoma Gas & Electric	SPP	5
4.	Jerry Nottnagel	Oklahoma Gas & Electric	SPP	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Kathleen Black	DTE Electric Co.			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Neil Kennings	Renewable Energy	RFC	
5.	Barbara Holland	SOC	RFC	
6.	Alan Randolph	Fossil Generation	RFC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Marcus Pelt	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee (SRC)		X								

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Ali Miremadi	CAISO	WECC	2
3.	Charles Yeung	SPP	SPP	2
4.	Kathleen Goodman	ISO-NE	NPCC	2
5.	Christina Bigelow	ERCOT	ERCOT	2
6.	Catherine Wesley	PJM	RFC	2
7.	Ben Li	IESO	NPCC	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ryan Strom	Buckeye Power, Inc.	RFC	3, 4, 5
5.	John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
6.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
7.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
8.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
9.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
10.	Ginger Mercier	Prairie Power, Inc.	SERC	3
11.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3.	Robert Hirchak	CLECO Corporation	SPP	1, 3, 5, 6
4.	Mike Kidwell	Empire District Electric Company	SPP	1, 3, 4
5.	James Nail	City of Independence, Missouri	SPP	3, 5
6.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

7. Sing Tay	Oklahoma Gas and Electric Company	SPP	1, 3, 5, 6
8. Jeff Wells	Grand River Dam Authority	SPP	1
9. J. Scott Williams	City Utilities of Springfield	SPP	1, 4
10. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
11. Robert Rhodes	Southwest Power Pool	SPP	2
12. Shannon V. Mickens	Southwest Power Pool	SPP	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. John Anasis	Technical Operations	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Individual	Steve Alexanderson	Central Lincoln People's Utility District			X	X					X	
20. Individual	Muhammed Ali	Hydro One	X		X							
21. Individual	Thomas Lyons	Owensboro Municipal Utilities			X							
22. Individual	Roger Dufresne	Hydro-Quebec Production					X					
23. Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X							
24. Individual	David Jendras	Ameren	X		X		X	X				
25. Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
26. Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
27. Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
28. Individual	Robert Fox on Behalf of David Austin	NIPSCO	X		X		X	X				
29. Individual	Diane Barney	New York State Department of Public Service									X	
30. Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
31. Individual	Thomas Foltz	American Electric Power	X		X		X	X				
32. Individual	Denise M. Lietz	Puget Sound Energy	X		X		X					
33. Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
34. Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Leonard Kula	Independent Electricity System Operator		X								
36.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
37.	Individual	Rich Salgo	NV Energy					X					
38.	Individual	Joshua Smith	Oncor Electric Delivery LLC	X									
39.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
40.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
41.	Individual	Daniel Duff	Liberty Electric Power					X					
42.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
43.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
44.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X							
45.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
46.	Individual	Jeremy Voll	BEPC	X		X		X		X			
47.	Individual	Daniel Mason	HHWP	X				X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for your contributions.

Organization	Agree	Supporting Comments of "Entity Name"
Seattle City Light	Agree	NPCC
Hydro-Quebec TransEnergie	Agree	NPCC
Kansas City Power and Light	Agree	SPP - Robert Rhodes
BEPC	Agree	Basin Electric agrees with the comments provided by the NRECA and Georgia Transmission Corporation.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		

1. **Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes**

Summary Consideration: The SDT has made the following changes due to industry comments:

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by that Balancing Authority.

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Changes to VSLs due to industry comments are shown in the redlined version of the standard.

Changes to the SOL Exceedance White Paper are shown in the redlined version of the paper provide for the fourth posting.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	We commented in the last posting to replace the word “ensure” in requirements R1 and R2, and in the standard’s other requirements where applicable. We note that “ensure” has been replaced with “address”. The Purpose of the standard is “To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” “Maintain” or “restore” are more appropriate words to use than “address”. The Time Horizon should only be “Real-time Operations”. “Ensure” in Measure M1 should also be replaced with the word selected to be used in R1. Regarding Requirement R3, Time Horizons should only be “Real-time Operations”. The 30 minute requirement in Requirement R13 is too restrictive and is inconsistent with EOP-008 which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore Real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: o Each Transmission Operator shall perform a Real-time Assessment at least once every two hours. o Each Transmission Operator shall perform a Real-time Assessment at least once every 30 minutes when the EMS and SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform Real-time assessments within two hours.

Organization	Yes or No	Question 1 Comment
		Requirement R7 has removed an important concept of TOP-001-1a Requirement R6. A supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, a supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency as not take the same voltage reduction action first. Simply stating, '... has implemented its Emergency procedures,' is not specific. TOP-001-1a Requirement R6 reads: R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Recommend the following change to R7 to target the TOP's requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator's region, if requested and able, provided that the requesting entity has implemented its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] In Part 10.2 the phrase '... as necessary by the TOP' is unclear. What TOP? Part 10.2 should be revised to be consistent with Part 10.1 and read: 10.2. Outside its Transmission Operator Area: Sub-parts 10.1.3 and 10.2.3 should be made consistent. "Ensure" remains in the posted requirement R13. Suggested rewording R13: Each Transmission Operator shall perform or have performed a Real-time Assessment at least once every 30 minutes. The "s" in system should be capitalized in Requirement R15.

Organization	Yes or No	Question 1 Comment
		R3, M3, M4, R5, M5, M6 all use the words to comply with operating instructions, but R4 and R6 use the words perform an operating instruction. The wording should be consistent. Measure M7 should be corrected to be written like M3 and M5 in the past tense: "...unless such assistance could not be physically implemented..." Measure M8 should be revised since R8, and the first part of M8 refer to operations "that result in, or could result in, an Emergency". Therefore, the last sentence in M8 should read: "If no such situations have occurred, the TOP may provide an attestation." Requirement R11 directs the Balancing Authority to "...monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load...". Monitoring Special Protection Systems is not a function of the Balancing Authority. Requirement R11 can be removed. Should M11 use the same examples of evidence as does M10, for example Energy Management System description documents? M12 should have a broader scope. If the auditor is to verify that the TOP did not operate outside IROL for a duration exceeding IROL TV, then the TOP should provide information on all occasions in which he operated outside IROL for any period of time. This would reflect the RSAW's audit approach. M12 should read: "Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL Tv. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the

Organization	Yes or No	Question 1 Comment
		Transmission Operator may provide an attestation that an event has not occurred." For IROLs there is a maximum exceedance duration specified, but for SOLs in R14/M14 there is no leeway. Thus if a SOL is exceeded for 30 seconds, the TOP must have evidence it initiated its Operating Plan. This applies also for the VSL in the Table of Compliance Elements. No difference is made if the TOP initiates its Plan within the minute or after half an hour. Entities generally have very many SOL exceedances a year and to document each of them a proof of Implementation of a Plan is unrealistic. Whereas IROLs may be more severe than SOLs, the measure is less stringent. In the C. Compliance section, under 1.3 Data Retention, Measure M14 is mentioned in the second and third paragraphs giving it two different data retention periods. There is a typing error in the fourth paragraph referring to R13/M13: "Each TOP shall each keep data (...)". Remove the second "each". In the Table of Compliance Elements there is a typing error in the last paragraph for Severe VSL listing for R8: "or more than 15%". For R9, replace "and" with "or" because generally only one of the elements will be outaged. The VSLs should be revised to read "...sustained outage of telemetering or control equipment, or monitoring or assessment capabilities, or associated communication channels." R10 and R11 should have similar VSLs. Presently if the TOP does not monitor a facility, it will be a Moderate VSL but if the BA does not monitor a facility, it is a severe VSL. Everything is lumped together for the BA whereas in reality it is not an all or nothing situation. R11 should therefore have VSLs equivalent to those in R10.

Organization	Yes or No	Question 1 Comment
		R14 should have different VSLs depending on the time it took the TOP to initiate its Operating Plan. R15 should have different VSLs depending on the time it took the TOP to inform its RC. Requirement R15 appears to be past tense, ‘ inform.. RC of actions taken...’. So one would believe that a pre-call is not required before actions are taken by the TOP. What is the purpose of this requirement? What is the added value in informing the RC after the fact of the actions that were taken to mitigate SOL exceedances? The TOP should be obligated to notify the RC if it cannot manage the exceedance on its own and needs assistance (another requirement). However, notifications via SCADA should be sufficient to address the concern. M15 - This measure does not include multi-modal communications. The TOP should be able to take credit for telemetered information (breaker operations) that communicates to the RC actions that have been taken. Also there is no time component for when to report. For example during, 5 minutes after, a day after. The word “own” should not be deleted from Requirement R16. It provides clarity that this is only pertaining to the equipment the Transmission Operator owns and not other equipment. The new requirement R19 addresses the data exchange capabilities needed. If non-BES facilities are to be included anywhere in the standard, they should be included in the BES by exception, especially since they are contributing to a SOL exceedance. R19 and R20 seem redundant with R10 and R11 since in R10 and R11 the TOP and BA are monitoring reliability required data, and they must have the data exchange capabilities. Also, TOP-003-3 requires the TOP to develop data specifications to support Real-time monitoring and operation of the

Organization	Yes or No	Question 1 Comment
		BES, and negotiate with data supplying entities the format, period and security protocol of the data exchange. This implies the requirement of a data exchange capability. We suggest removing R19 and R20. What defines a neighboring Transmission Operator Area? There are many instances where the loss of a facility in, let's say in Transmission Operator Area "A", which is not electrically "adjacent" to Transmission Operator Area "B", impacts Transmission Operator Area "B".

Response: The SDT agrees and has replaced 'address' with 'maintain' as suggested by you and other commenters. See summary for language.

The SDT disagrees. Same-Day Operations is a legitimate time horizon when considering actions to maintain BES reliability. No change made.

The SDT agrees and has replaced 'ensure' with 'maintain' in Measure M1.

Since no change was made to the time horizons in Requirements R1 and R2, there is no change applicable to Requirement R3.

The SDT believes that approved EOP-008-1, Requirement R1, Part 1.5 deals with restoring functionality, allowing for a 2-hour time period to handle transitions from primary to backup functionality. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen during that transition. That requirement states that an entity is still responsible for managing the risk during transition. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is in agreement with the principle espoused in approved EOP-008-1 and is not unrealistic or overly burdensome in today's operating environment. This is also consistent with approved IRO-008-1, Requirement R2. No change made.

The SDT agrees and has added the term. See summary for language.

Requirement R10, Part 10.2 is nested within the main body of Requirement R10. Everything that comes after the main body of Requirement R10 refers back to the subject of Requirement R10. Therefore the Transmission Operator cited in Requirement R10, Part 10.2 refers back to the original subject Transmission Operator.

The SDT agrees and has made the suggested change. See summary for language.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">The language in Requirement R10, Parts 10.1.3 and 10.2.3 is consistent. Part 10.1.3 specifically contains the phrase ‘as necessary by the Transmission Operator’ because Parts 10.1.1 and 10.1.2 do not have this constraint. That specific language is not needed in Part 10.2.3 because the language in Part 10.2 already states that condition as it applies to all 3 sub-parts. No change made.

The SDT believes that ‘ensure’ is the correct terminology in Requirement R13. The intent of the SDT is that the entity must make certain that someone, itself or another designated entity, is performing the Real-time Assessment as specified. “Ensure’ is the proper connotation for those actions. No change made.

The SDT agrees and has capitalized the term. See summary for language.

The SDT agrees and has made the suggested changes for consistency. See summary for language.

The SDT agrees and has changed Measure M7 as suggested. See summary for language.

The SDT agrees and has changed Measure M8 as suggested. See summary for language.

The SDT believes that knowledge of Special Protection Systems that impact generations is incumbent for the Balancing Authority. Item 19 of the Balancing Authority Functional Entity description in Functional Model v5 states: “Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.” The SDT believes that this may include the status of Special Protection Systems that impact generation. Special Protection Systems could result in the tripping of multiple generation facilities, which may impact the Balancing Authority reserve requirements. No change made.

The SDT agrees and has changed Measure M11 as suggested. See summary for language.

The SDT agrees and has changed measure M12 as suggested. See summary for language.

The SDT believes that the assertion that there is no leeway for an SOL exceedance is incorrect. The SDT would agree that there is no leeway for an SOL violation but there are different response times based on the type of SOL Exceedance that has occurred. SOL’s are defined by the Reliability Coordinator and specific operator actions to mitigate SOL exceedances would be defined in that entity’s Operating Plan. An SOL Exceedance is further described in the SOL Exceedance White Paper. Please refer to the SOL White Paper for additional details. No action required.

The SDT agrees. The first instance of Measure M14 is incorrect and this error has been corrected.

The SDT agrees and has removed the second instance of ‘each’ as suggested.

The SDT agrees and has made the suggested correction to the Severe VSL.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
The SDT has replaced 'and' with 'or' in the Requirement R9 VSLs. The SDT agrees and has changed the Requirement R11 VSLs accordingly. The SDT disagrees as it believes that the Operating Plan initiation is a binary action. Waiting to initiate the plan is dangerous and such actions should not be tolerated. No change made. The SDT believes that it is counter to reliability to place a time tag on informing the Reliability Coordinator. The operator should be concentrating on the reliability issue and not be concerned with adhering to an arbitrary time period for informing entities. Since no time frame is deemed appropriate for the requirement itself, the SDT does not believe that time periods should be introduced in the VSLs. No change made. Requirement R15 is intentionally written in the past tense as it is feedback to the Reliability Coordinator after the fact. The Transmission Operator has primary responsibility for mitigating SOL exceedances. Pre-calls to a Reliability Coordinator are not ruled out by this standard and can take place at the discretion of the Transmission Operator if it believes they are necessary or if prior agreements between the Reliability Coordinator and Transmission Operator dictate such an action. Regardless, the SDT believes that it is an important for BES reliability for the Reliability Coordinator to know what actions were taken to mitigate the situation. How such notification is made is up to the entities involved as 'how' is not within scope of standards. If two entities agree that SCADA provides sufficient notification that is an acceptable method of notification. Nothing in this requirement or standard precludes that. No change made. Measure M15 is not a hard and fast listing of every method that can be used to impart the required information. The language states 'such as' so that there is some degree of flexibility in how to comply with the requirement. The SDT believes that telemetering data/information could be an acceptable method. The SDT can't introduce timing requirements in a measure if they are not cited specifically in the requirement. The SDT did not place timing requirements in the standards because the SDT believes that such inclusion could be detrimental to reliability as it would force a Transmission Operator to focus on how quickly to perform this task as opposed to concentrating on alleviating the reliability concern. No change made. 'Own' was removed due to multiple industry comments in a previous posting. The SDT agreed with the comments stating that the term was redundant. No change made. Requirement R19 does not directly address the concept of non-BES facilities. However, when that topic does occur the SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES		

Organization	Yes or No	Question 1 Comment
Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. See summary for language. Reliability Standards must include explicit requirements and can't make assumptions as to things being in place in order to be able to comply with a particular requirement. All requirements must be spelled out and applied as needed. This was made clear in the FERC NOPR delivered in response to the Project 2006-06 and 2007-03 filings. No change made. Due to your comment and others, 'neighboring' is no longer used in this standard.		
BC Hydro	No	BC Hydro's concern is that the Reliability Directive is replaced with Operating Instruction in the standard. The scope of "Operating Instructions" broadens to non-emergency situations. Requirement R3 and R4 have the BA's complying with TOP's Operating Instructions. BC Hydro's concern is that there may be a conflict between the BA and the TOP. Requirement R3 provides exceptions for complying, but only for safety, equipment regulatory or statutory requirements. Nowhere does the Requirement address conflict in reliability requirements: for example, a TOP in our area issues an instruction to eliminate a voltage limit issue, and this action may cause another limits issue for another TOP. There appears to be no "out" clause based on reliability conflicts - such as deferring to an assessed lesser reliability impact. BC Hydro recommends revising these Requirements to allow for an "out" clause.
Response: Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC's acceptance of the standards. No change made. The standards have been set up so that the Transmission Operator determines SOLs and is the primary responsible entity for them. However, the Reliability Coordinator still maintains an obligation to monitor SOLs. This means that the Reliability Coordinator will be		

Organization	Yes or No	Question 1 Comment
able to apply its wide-are view on actions taking place and will step in as needed if actions are causing other problems that a specific Transmission Operator is unable to ascertain. No change made.		
PacifiCorp	No	Definition of Real-Time Assessment contains provisions that will make compliance with the Requirements unattainable. First, the applicable inputs to the assessment include among other things, “known Protection System status or degradation.” Real time tools are generally incapable of consideration of the performance of protection systems, and accordingly conducting these assessments prescribed in the Requirements will fall short of the expectation.
Response: The SDT recognizes that Real-Time Assessments may not automatically include “known Protection System status or degradation”. However, once the issue is communicated to the Transmission Operator, the Transmission Operator has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.		
Bureau of Reclamation	No	First, Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3 R1-R6 and the entire TOP/IRO Revisions. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators. During normal operations, Reclamation does not believe that Transmission Operators should be able to always issue mandatory Operating Instructions to generators that may damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers). Reclamation disagrees with the drafting team's assertion that "the definition for Reliability Directive is not needed due to work ... on the definition of Operating Instruction." Reclamation believes that additional conversations with FERC may be necessary, and that TOP-001-3 should maintain the important concept that Balancing Authority and Transmission

Organization	Yes or No	Question 1 Comment
		Operators only may issue Reliability Directives to address Emergencies or avoid Adverse Reliability Impacts. Reclamation also believes that Balancing Authorities and Transmission Providers should be required to inform entities when they are issuing a Reliability Directive. In some instances, Balancing Authorities and Transmission Providers have decided after the fact that an instruction was a Reliability Directive. Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked if an entity does not describe the instruction as a Reliability Directive. Second, Reclamation also continues to disagree with the drafting team's proposal to revise TOP-003-3 to require Generator Owners, Generator Operators, and Transmission Owners to meet any data specification outlined by Transmission Operators or Balancing Authorities. Like TOP-003-1, TOP-003-3 should outline a specific continent-wide standard like the submission of planned generation outages over 50MW by noon on the day before the outage, a requirement that has existed for 7 years. Reclamation does not support TOP-003-3 because it does not clearly define what types of data entities can request or may be required to provide, and will create significant operational challenges for entities operating in multiple Transmission Operator and Balancing Authority areas. As an example, Reclamation owns and operates over 50 hydroelectric facilities in seven control areas and this change would prevent Reclamation from adopting a uniform approach to demonstrating compliance with TOP-003. Under the current version of TOP-003, Reclamation can present a uniform approach to demonstrating that it submits planned outages before noon the day before the outage. In fact, like many generation entities, Reclamation generally submits planned outages more than a year in advance and plans non-routine outages as far in advance as practical. Under the proposed version of TOP-003-3, Reclamation would have to track and adjust individual generator Standard Operating Procedures (SOPs) to meet different and

Organization	Yes or No	Question 1 Comment
		perhaps ever changing data specifications developed by each Transmission Operators, which could result in high costs for little reliability benefit.
Response: Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC's acceptance of the standards. In the FERC NOPR, it was made clear that the concept of a special type of communication for Emergency situations was not considered acceptable. Operating Instructions issued to generators are not intended to damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers). Requirements R3 and R4 define provisions under which Balancing Authorities, Generator Operators, and Distribution Providers are not obligated to follow Operating Instructions issued by the Transmission Operator. No change made. Proposed TOP-003-3 was approved by the industry and is not a part of this current proceeding.		
Con Edison, Inc.	No	Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours. Requirement R7 raises jurisdictional concerns. We recommend the following change to R7 to target the TOP's requirement to assist other TOPs to those in the same RC area: R7. Each Transmission Operator shall assist other Transmission Operators within their Reliability Coordinator's region, if requested and able, provided that the requesting entity has implemented

Organization	Yes or No	Question 1 Comment
		its Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Response: The SDT believes that approved EOP-008-1, Requirement R1, Part 1.5 deals with restoring functionality, allowing for a 2-hour time period to handle transitions from primary to backup functionality. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen during that transition. That requirement states that an entity is still responsible for managing the risk during transition. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is in agreement with the principle espoused in approved EOP-008-1 and is not unrealistic or overly burdensome in today's operating environment. One option is to have an Operating Procedure which has the Reliability Coordinator perform the Real-time Assessment on behalf of the Transmission Operator under an EOP-008 scenario. This is also consistent with approved IRO-008-1, Requirement R2. No change made. The SDT agrees and has made the suggested change. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation. See summary for language.		
MRO NERC Standards Review Forum	No	R1 and R2 are ALL encompassing actions that cover every actionable NERC Requirement that the TOP and BA must accomplish. As written, "Each (BA, TOP) shall act to address the reliability of its (BA, TOP) Area via direct actions or by issuing Operating Instructions". EOP-002-3.1, R6, IRO-001-1.1, R8, are two examples where there must be "immediate" actions by the BA or TOP. If "via direct actions" is maintained in this proposed Standard, there will be a non-compliance double jeopardy impact if the BA or TOP violates an "immediate action" Requirement. Is the intent of R1 and R2 to issue Operating Instructions when the BA or TOP cannot maintain a reliability of their associated area? The NSRF wishes to points out that the Standards Process Manual section 2.4 describes a "Results Based Requirement" as "Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to

Organization	Yes or No	Question 1 Comment
		achieve a specific reliability objective and not how that objective is achieved". R1 & R2 with their broad, general language do not meet the threshold for a "Results Based Requirement". The NSRF agrees with issuing Operating Instructions when required to maintain your system in a reliable state. But the all-encompassing "via direct actions", is applicable to over 460 Requirements that a BA must comply with. How is this going to be measured for the BA (or TOP)? Are voltage schedules going to be measured when that is covered in the VAR Standards? Is seems to be a catch all Requirement. A possible rewrite of R1 and R2 could read: "Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance ". M1 does not reflect the current language of the rewritten R1. The word "ensure" still resides in M1. R9. Concerning "sustained outages", is there a minimum reporting threshold for this undefined term? EOP-004-2, Event Type "Complete loss of voice communication capability" and "Complete loss of monitoring capability" has a 30 minute continuous threshold. The NSRF recommends using the same bright line criteria of EOP-004-2 as stated above. R13. Real-time Assessment: The NSRF still has concerns about how entities will incorporate "protection system status" into their real-time 30 minute assessment to be fully compliant. More clarity is needed for entities to verify that they have met the requirement. How are entities expected to show that their operators are aware of protection system status (as defined in the proposed Real-Time Assessment definition) and understand the system impact if a protection system is out-of-service? If policies, procedures, and snapshots of system operator tools are sufficient, this can be done. However, large scale state estimator real-time contingency assessments used have limitations. State estimators run DC power flows based on programed line and node based contingencies. Protection system

Organization	Yes or No	Question 1 Comment
		status changes that modify the lines and nodes studied may not be easily incorporated into state estimator systems in 30 minutes. Protection system coverage could easily change for known and unknown conditions. Known changes can include PRC testing. The PRC testing standards have mandated large amounts of testing for even moderately sized system so that daily testing must occur to meet mandatory testing timeframes. The large volume of PRC testing could make accounting for all protection system status changes within 30 minutes difficult to verify and puts entities at risk for maintaining perfect compliance to a large number of requirements since many of the TOP / IROL standards include the real-time assessment definition. Recommend that "protection system status" be deleted from the definition or at a minimum clarify that protection system status consideration by system operations is acceptable to be compliant, since "status consideration" equates to "situational awareness". As written in R13:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] M13.Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence. With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall "ensure that a Real-time Assessment is performed at least once every 30 minutes;" however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP."

Organization	Yes or No	Question 1 Comment
		Measure M13 would need commensurate edits to conform with this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the "situational awareness" because they will not know "known Protection System and Special Protection System status or degradation..." per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words "have situational awareness" in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. Please review the below violation which is based on Auditor notes (for TOP-002-2, R11). This shows that simple "situational awareness" is predicated on "system analysis", which the NSRF looks at as the entities RTCA. A second concern with the TOP-001-

Organization	Yes or No	Question 1 Comment
		3 definition of Real time assessment, the recent TOP-002-2.1b R11 auditor guidance in the new RSAW, and a recent TOP-002-2.1b R11 violation cited below, is the proposed requirement is not technically feasible today. The three items listed just above in conjunction require an on-line dynamic stability assessment tool that can run multiple AC dynamic angular and voltage stability assessments in less than 30 minutes considering EMS input of the most recent alarm, SPS, and degraded state alarm statuses. The NSRF isn't aware of RTCA technology that can meet these requirements. Alternately, the assessment falls to human manpower to perform these studies. Entities must identify a RTO, RC, or PA with staff available 24/7 to perform this or train its own 24/7 staff. It takes time to train dynamic stability staff and time to change the model to capture "known Protection System" statuses.TOP-001-3 Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)TOP-002-2.1b violation: (note this is publically posted in the most recent November compliance and enforcement spreadsheet) TOP-002-2.1b R11. On two occasions, SCS-Trans' updated Bulk Electric System (BES) studies failed to reflect current system conditions. Specifically, two unscheduled outages of Protection System components, one for a 500 kV transmission line and one for a 230 kV transmission line, were not considered in SCS-Trans' operating studies. TOP-002-2.1b RSAW auditor Guidance: Evaluation of Protection System Outages Protection Systems must operate and clear faults within the required clearing time to satisfy system performance requirements. All outages of

Organization	Yes or No	Question 1 Comment
		Protection Systems or their components that affect the reliability performance of the transmission system must be evaluated for the periods they are scheduled, in the planning horizon in TPL assessments and in the operational planning timeframe through operating studies. For example, if a transmission line has A and B protection packages that are not functionally equivalent and the outage of one protection package affects the operating speed of the Protection System, the impact of slower fault clearing on the power delivery capability of the Bulk Power System (BPS) must be considered in the assessments and studies. Such impacts also must be considered when a transmission line has a single protection package and one component of the package (e.g., the communication system) is taken out of service

Response: The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal - either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes.

Measure M1 has been corrected.

The SDT agrees and has made the suggested change. See summary for language.

The SDT recognizes that Real-Time Assessments may not automatically include “known Protection System status or degradation”. However, once the issue is communicated to the Transmission Operator, the Transmission Operator has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.

The suggested language change to Requirement R13 presents ambiguity and is not measurable. No change made.

As there was no change to Requirement R13, there is no need for a corresponding change to Measure M13.

The SDT recognizes that Real-Time Assessments may not automatically include “known Protection System status or degradation”. The SDT also recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. However, once the issue is communicated to the Transmission Operator, the Transmission Operator

Organization	Yes or No	Question 1 Comment
has the capability to determine if Contingency definitions need to be modified and analyze the impact of such changes. No change made.		
Oklahoma Gas & Electric SPP Standards Review Group	No	M1 - Replace 'ensure' with 'address' as in the requirement. R8 - With the removal of 'other' when referring to 'known impacted Transmission Operators' an overzealous auditor could require a Transmission Operator experiencing a condition which could be an Emergency or result in an Emergency would have to inform itself. Using 'other known impacted Transmission Operators' eliminates this situation. We recommend the drafting team return 'other', in the suggested location, to the requirement, measure and VSLs. R8 VSLs - If the drafting team decides not to make this suggested change, the term 'other' needs to be removed from the first 'OR' in the Severe VSL. In the last 'OR' of the Severe VSL insert the phrase '..., whichever is greater,...' between 'Authorities' and 'of'. R9 - We appreciate the drafting team attempting to add specificity to Requirement R9; however, 'sustained' is undefined. How does a Transmission Operator determine whether or not they are compliant with this requirement? What ensures auditors will consistently apply the terminology. We recommend the drafting team incorporate language consistent with COM-001-2, R10 which requires notification for outages lasting 30 minutes or more. If 30 minutes is determined to be too long, reduce the time to 15 minutes. We would like to suggest adding the term 'known' in front of 'impacted' in the second line of Requirement R9. We would like for the drafting team to help provide some clarity in Requirement R9..... does it apply to Planned Outages? Also, we noticed that the term 'planned' was removed from Measurement M9. Our question to the drafting team was this your intent to remove this term and if so would

Organization	Yes or No	Question 1 Comment
		you provide clarity on why the term should be removed. We would like to suggest that the drafting team tie Requirement R9 to the Data Specifications of TOP-003-3 as suggested in the Mapping Document. Also, we would like to thank the drafting team for their willingness to adjust to many suggestions that are submitted and we truly appreciative for all or your time and efforts. R9 VSLs - Delete the phrase 'NERC registered' and insert the phrase '..., whichever is greater,...' between 'entities' and 'of' in the 'OR' of the Severe VSL. R10 VSL - The drafting team should consider adding a 2nd 'OR' to the High VSL which states 'The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and one of the items listed in Requirement R10, Part 10.2.' R16 - We would like for the drafting team to provide more clarity on the word "telecommunication". The word "telecommunication" should apply only to specific outages or maintenance work done on the SCADA/EMS that affect the System Operators. R19 & R20 Moderate and High VSLs - Replace 'entity' with 'entities'.

Response: Measure M1 has been corrected.

The SDT removed 'other' due to multiple industry requests in a previous posting. The SDT agreed with the commenters that the term was redundant. The SDT believes that the situation cited where an entity would have to inform itself is not realistic and not indicative of actual operations. No change made.

The SDT agrees and has made the suggested correction to the Requirement R8 Severe VSL.

The SDT agrees and has made the suggested change. See summary for language.

Requirement R9 does apply to planned outages and the SDT has revised the language to provide clarity on the topic. See summary for language.

Organization	Yes or No	Question 1 Comment
The SDT agrees and has made the suggested change to the Requirement R9 Severe VSL. The SDT agrees and has made the suggested change to the High VSL for Requirement R10. The SDT has changed the language of the requirement to provide clarity. See summary for language. The SDT agrees and has made the suggested change to the Requirement R19 and R20 VSLs.		
Tennessee Valley Authority	No	TVA feels that requiring a TOP to monitor neighboring facilities that are non-BES to determine SOL violations should not be required (see R10., 10.2.3). If non-BES facilities are required for the reliable operation of the transmission system they should first be included into the BES by use of the Rules of Procedure exceptions process.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Colorado Springs Utilities	No	Thank you SDT members for all of your work, the following were our comments on the proposed standard language. We will be voting affirmative, but think comments below crucial the final modifications to the standard. 1. "Ensure" was removed from R1 and R2 but please also remove it from M1 and M2.2. 2. R3 - LSE needs to be removed as this function is soon to be retired. 3. With the new definition of RAS just voted on, it would be best to replace RAS with SPS as "SPS" is going away.

Organization	Yes or No	Question 1 Comment
		4. Please change "maintain" to address in R19/M19 and R20/M20. This has similar implications of "ensure." Of course we should do all in our power to maintain and ensure the bulk electric system, but there will be situations (no matter how many standards are in place) where industry may not be able to ensure or maintain reliability. To use such language is putting an unrealistic expectation in place that gives the regulator the ability to use our own words to find fault, even when no fault is present.
Response: The SDT agrees and has corrected the measures. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project. Similar to the situation with Load-Serving Entity above, Remedial Action Scheme and Special Protection System are in the midst of a possible change. At its November 2014 meeting, the Board adopted this change and a future filing with FERC will ask for approval of this action. The best approach for this project on this issue at this time is to leave Special Protection System in place as it is used in multiple places throughout the project in approved standards and the SDT would like to retain consistency in terminology and to let the subsequent project make all changes applying to Special Protection System so that industry can see them all at one time. No change made. 'Ensure' does not appear in Requirements R19 or R20. No change made.		
JEA	No	For R4&5 the timing is vague. Should it be done immediately, within 30 minutes, etc.

Organization	Yes or No	Question 1 Comment
		For R9 we are concerned that "sustained" is vague. If it lasted 2 minutes, was that a sustained outage? R10 should only include BES elements. Items of concern can be added through the inclusion process. R13 should have an exclusion that allows procedures to be implemented when system information is unavailable to reduce the risk instead of simply requiring real-time assessments be performed at least every 30 minutes. Even having a complete redundant EMS system might not prove sufficient to prevent a violation. R19 & 20 should require other BAs and TOPs to participate.

Response: The SDT believes that the timing issue will take care of itself. If an entity can't comply it is in its best interests to notify the Transmission Operator/Balancing Authority as soon as possible. Any attempt to mandate a specified time would be self-defeating and overly prescriptive and thus not in the best interest of BES reliability. No change made.

The SDT agrees and has changed the requirement accordingly. See summary for language.

The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.

The SDT has not stated how Requirement R13 is implemented as 'how' to do something is outside scope for Reliability Standards. If an entity can devise a procedure to accomplish the stated goal of the requirement then such a procedure would be an acceptable mechanism. One option is to have an Operating Plan which has the Reliability Coordinator perform the Real-time Assessment on behalf of the Transmission Operator under an EOP-008 scenario. No change made.

Organization	Yes or No	Question 1 Comment
The SDT believes that only one entity can be ultimately held responsible for these types of requirements and has written Requirements R19 and R20 accordingly. The ‘other’ entities will need to fall in line as they will be in violation of proposed TOP-003-3, Requirement R5 if they do not. No change made.		
Duke Energy	No	General Comments: Duke Energy is concerned with the uncertainty surrounding the inclusion and/or exclusion of Load Serving Entity in various Standards Projects. This inconsistency among Standard Drafting Teams creates uncertainty in the industry as to the expectations of the LSE, or whether the LSE will even be a applicable function. A more consistent application of the LSE function in proposed NERC standards is needed. R1: Based upon the comments provided below, Duke Energy suggests that R1 be focused on the TOP issuing Operating Instructions and suggests the following revision to R1 for clarity: ”Each Transmission Operator shall issue Operating Instructions, as necessary, to maintain the reliability of its Transmission Operator Area”. We believe the intent is for the TOP to “maintain” the reliability of the TOP Area by Issuing Operating Instructions. Duke Energy believes that by using the term “address” in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term “maintain”, the standard would require the entity to identify the problem and maintain the reliability of its TOP Area. Lastly, Duke Energy has concerns with the use of the term “act” in R1 and R2. As currently worded, absent the TOP issuing an Operating Instruction, R1 states that the TOP shall “act”, in other words, do its job. If an entity fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other TOP standard, it could be argued that the entity failed to perform a certain “act”, which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase “issue

Organization	Yes or No	Question 1 Comment
		Operating Instructions" eliminates the possibility of a double jeopardy situation. R2:Based upon the comments provided below, Duke Energy suggests that R2 be focused on the BA issuing Operating Instructions and suggests the following revision to R2 for clarity: "Each Balancing Authority shall issue Operating Instructions, as necessary, to maintain the reliability of its Balancing Authority Area". We believe the intent is for the BA to maintain the reliability of its BA Area by Issuing Operating Instructions. Duke Energy believes that by using the term "address" in the current draft, the standard would only be requiring an entity to identify the problem and take action without any stated goal or result. We feel that by using the term "maintain", the standard would require the entity to identify the problem and maintain the reliability of its BA Area. Lastly, Duke Energy has concerns with the use of the term "act" in R1 and R2. As currently worded, absent the BA issuing an Operating Instruction, R2 states that the BA shall "act", in other words, do its job. If the BA fails to perform some action in an effort to maintain reliability in its Area, the entity would be in direct violation of this standard. In the event that an entity violated any other BA standard, it could be argued that the entity failed to perform a certain "act", which presents a possible double jeopardy situation wherein the failure to act, violating one standard could be construed as a violation of the proposed TOP-001-3. We suggest the use of the phrase "issue Operating Instructions" eliminates the possibility of a double jeopardy situation. R9:Duke Energy would like the SDT to clarify the time duration of a "sustained outage". It is unclear if an outage lasting longer than 10min, 20min, 30min, etc., would be considered a sustained outage. Was it the SDT's intent to allow entities the flexibility to define what constitutes a "sustained outage"?

Organization	Yes or No	Question 1 Comment
		SOL Exceedance document: (1) Duke Energy suggests replacing "Thermal Limit Exceeded" with "SOL Limit Exceeded" to provide clarity in the example given in Table 1. (2) Duke Energy does not believe that the System Operating Limit Definition and Exceedance Clarification document should be attached to the TOP-001-1 standard. Instead, we believe it should be a standalone guidance document for the industry. If this were to occur, Duke Energy would likely vote "Affirmative" for TOP-001-1 as written.

Response: The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.

The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal - either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes

The SDT agrees and has changed Requirement R9 accordingly. See summary for language.

The SDT agrees and has made the suggested change in the redlined version of the SOL Exceedance White Paper.

The SOL Exceedance White Paper will not be attached to the standard but will be posted to a separate accessible place on the NERC web site. The exact URL is not available at this time but will be shown in Section F in the final posting of the approved standard.

Organization	Yes or No	Question 1 Comment
ISO/RTO Council Standards Review Committee (SRC)	No	SRC members generally agrees with the modifications to TOP-001-3 with the following additional recommendations for clarity, consistency, and/or to eliminate redundancy: 1. In Requirement R1, it is recommended that “address” is ambiguous and should be revised to “maintain” or “preserve” and that “[V]ia direct actions or by issuing Operating Instructions” should be revised to state “by initiating direct actions or issuing Operating Instructions.” Also, the measure M1 should be revised for consistency. 2. Review of modifications to IRO-001-4, Requirements R1, R2, and R3 to ensure consistency with the proposed revisions to TOP-001-3, Requirements R1 - R6.3. Requirement R7 has not retained an important concept contained within the previous requirement (TOP-001-1a - R6), which is that a supporting TOP should not be obligated to activate emergency procedures beyond those activated by the TOP that is in the emergency. As an example, the supporting TOP should not be obligated to go into voltage reduction if the TOP with the emergency has not taken the same voltage reduction action first. Hence, the phrase ‘... has implemented its Emergency procedures,’ is less specific than the previous standard and should be revised to provide ‘... has implemented its comparable Emergency procedures.’ 4. Requirement 10 seems duplicative in function with IRO-003, which requires the RC to monitor facilities associated with System Operating Limits (SOLs) and represents an overlap of the RC’s responsibility with the TOP draft requirement. Specifically, the TOP would have a requirement to monitor facilities outside of its TOP area that could affect SOL exceedances within its TOP area when the RC is already tasked with the “wide-area” view. This is in direct conflict with the Functional Model definition of a TOP which limits TOP responsibility to assets within its area.

Organization	Yes or No	Question 1 Comment
		Further, it is recommended that the term “non-BES” Be removed from Requirement R10. The “inclusion” process should capture all equipment that are sub-100 kV, but that affect BES reliability and bring this equipment into scope. Finally, in Requirement R10.2, the phrase ‘... as necessary by the TOP’ is unclear and should be redrafted to be consistent with 10.1 “10.2. In the neighboring Transmission Operator Area.” Conforming changes should also be made to Requirements R10.1.3 and 10.2.3. NOTE: this comment is not supported by PJM 5. The SRC appreciates the SDT’s effort to clarify the obligations of Balancing Authorities under Requirement R11. However, it respectfully submits that “in order to be able to perform its reliability functions” may still be ambiguous, resulting in subjective determinations of compliance. Additional revision is proposed to mitigate this ambiguity and to ensure that the reliability functions being referenced are clear: ”Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange-generation balance within its Balancing Authority Area, and support Interconnection frequency in real-time.” 6. The SRC respectfully submits that R15 is not necessary to ensure an Adequate Level of Reliability. Specifically, since the exceedance would have already been addressed or is being actively managed by the TOP and communication would already be occurring with impacted parties pursuant to other requirements, a requirement to inform the RC isn’t needed. If R15 is maintained, the SRC suggests including SCADA information in the Measurement so that the TOP can “inform” the RC through this mechanism. NOTE: this comment is not supported by PJM 7. The SRC reiterates it serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without requirements in TOP-001-3

Organization	Yes or No	Question 1 Comment
		addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unstudied state. In previous postings, the SRC expressed a concern that, by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be required to reconfirm or reestablish valid SOLs or IROLs when entering an unstudied state. We recognize that, by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, entities will always be assessing the reliability of the BES. However, we continue to disagree with this rationale and provide additional information in response to the SDT's response to our last comment. In response to the SDT's indication that it does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv, the SRC responds that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and, therefore, there does not exist an updated, valid limit until it is re-determined (or reconfirmed). Thus, if an unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover, then entities may find themselves in an unknown operating state. For example, in the Northeast, such as Quebec, Ontario and New York, SOLs/IROLs are observed to guard against transient or dynamic instability. These limits are normally developed using off-line analyses, as they cannot be determined within a short time using any on-line analysis tools available today. Predetermined reduction or judgment may need to be applied when system conditions, such as two or more critical facilities are out of service, diverge from the assumptions utilized in reliability assessment and other studies. In these circumstances, e.g., when an unstudied state is encountered, a necessary first step for the operating entities in these areas is to reconfirm or recalculate the limits that are valid and applicable for the prevailing

Organization	Yes or No	Question 1 Comment
		conditions. The reconfirmed or reestablished limits will become the target to which the system must be adjusted. Given the use of off-line studies to set limits and identify complex system conditions, the SRC believes that the OPA and RTA are good tools, but caution that these tools only look ahead at anticipated conditions and assess real-time situations in response to system changes. Accordingly, by themselves, they are not limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, where such limits may not exist, the OPA and RTA are not the tools to calculate limits for the anticipated or prevailing conditions, especially for stability restricted SOLs/IROLs. To summarize, it is possible for the system to be in an unstudied or unknown state where established limits either don't apply or limits have not yet been established. While the RTA, OPA, and established Operating Plans can be quickly and easily applied to anticipated conditions, changes during real-time operation can render the assumptions and pre-determined limits invalid and, hence, the responsible entity cannot rely on these tools should these circumstances occur. Thus, the SRC once again urges the SDT to modify TOP-001-3 to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in off-line calculations. NOTE: this comment is not supported by CAISO; ERCOT; MISO or PJM.

Response: 1. The SDT agrees and has made the suggested change. See summary for language.

The SDT agrees and has made the suggested change.

2. The SDT has reviewed the indicated requirements for consistency and believes that they are consistent. No change made.

The SDT agrees and has added the term. See summary for language.

4. The SDT does not believe that this requirement is duplicative. The SDT believes there is a distinction between 'identifying' (Reliability Coordinator task) versus 'determining' (Transmission Operator task). The Reliability Coordinator still retains responsibility

Organization	Yes or No	Question 1 Comment
for the 'wide-area' view – nothing the SDT has done affects that responsibility. However, Requirement R10 has been modified for clarification due to comments. See summary for language. The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. The SDT used the phrase 'as necessary by the Transmission Operator' to allow the Transmission Operators maximum flexibility in deciding what data it needs. Every situation is different across the country. Any attempt to create a national standard stating exactly what data a Transmission Operator needs would be fraught with error when applied to all of the unique and specific configurations employed throughout North America. Therefore the language was crafted to recognize this fact and to place the onus of responsibility as to what is required on the individual Transmission Operator. No change made. 5. The SDT agrees and has made the suggested change. See summary for language. 6. The SDT believes that it is an important for BES reliability for the Reliability Coordinator to know what actions were taken to mitigate the situation. How such notification is made is up to the entities involved as 'how' is not within scope of standards. If two entities agree that SCADA provides sufficient notification that is an acceptable method of notification. Nothing in this requirement or standard precludes that. No change made. 7. The SDT understands the concern of moving to an unknown state which it interprets as a condition that has not been previously studied. However, the SDT believes that there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore, the standard does not prohibit an entity from performing an RTA more frequently in response to a unplanned system event. No change made.		

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) There are several issues with the draft standard of TOP-001-3. First, we disagree with the inclusion of the Load-Serving Entity (LSE) as an applicable entity. This function is being removed from the NERC Rules of Procedure and should not be included in the draft standard. TOP-001-3 already applies to the Distribution Provider (DP), so there will not be a gap in the future because LSEs are required to also be registered as DPs. We recommend removing the LSE from the applicability section for consistency with the revised NERC Rules of Procedure and to avoid a future standards project to correct this issue. In regards to timing, the NERC BOT will likely have approved removal of LSE before this is even approved in a final ballot by the ballot body. (2) Requirement R1 and Requirement R2 are problematic because they are vaguely written and could result in additional compliance burdens for a TOP or BA when there is an event. As currently written, any time that a TOP or BA has an outage there could be a violation because the entity did not address the reliability of its area. These requirements will be used in enforcement as additional fines without benefitting reliability because they do not state what actions should be taken. We also disagree with the High VRF and Severe VSL for these standards. These requirements are vague and need further refinement. (3) Requirements R3, R4, R5, and R6 should not apply to the LSE, as previously stated above. (4) Requirement R8 needs to be revised to remove the words “could result in an Emergency.” There are numerous situations that “could” result in an Emergency, but do not. This language is ambiguous and immeasurable, and should be removed. (5) Requirement R9 has improved with the addition of “sustained outages” to clarify that notification is not required for momentary events. However,

Organization	Yes or No	Question 1 Comment
		R9 is not clear as to the outage thresholds that would require a notification. When must the BA or TOP notify its RC? The requirement is ambiguous as written, which will lead to varying interpretations for compliance. This requirement needs to be revised to provide additional clarity when a notification to the RC is required. (6) Requirement R10 and part 10.1 are duplicative in listing "within its Transmission Operator Area." If taken as a whole, R10 states that "Each TOP shall monitor the following as necessary for determining SOL exceedances within its TOP Area: 10.1. Within its TOP Area: 10.1.1. Facilities..." This requirement needs to be revised to have proper sentence structure. (7) Part 10.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. There is no reason to include non-BES Elements in the requirement. Parts 10.1.3 and 10.2.3 that reference "non-BES facilities" should be struck. (8) Thank you for the opportunity to comment.

Response: 1. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.

Organization	Yes or No	Question 1 Comment
2. The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal - either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement. Specific actions for specific situations will be covered under the applicable standards. The wording of the requirements has been changed to provide additional clarity. See summary for changes 3. The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project. 4. The SDT believes that the language is correct as stated and consistent with the intent of the standards. If an entity performs an analysis and an Emergency situation is forecasted, then that entity should inform entities of this condition as per the requirement. An example could be the notification of an Emergency outage that would result in a known Stability issue requiring the execution of Operating Plans. No change made. 5. The SDT agrees and has made changes to the requirement. See summary for language. 6. The SDT disagrees. The first instance of 'within its Transmission Operator Area' refers specifically to the function of determining SOL exceedances. The second instance lays out what must be done within its own area to accomplish this task. No change made. 7. The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	BPA reiterates its comments from the previous period on TOP-001-3: BPA suggests referencing the System Operating Limit (SOL) Definition and Exceedance Clarification white paper in the language of the Requirements, as Regional Entities are not required to audit to appendices, unless indicated by the language of a Requirement. BPA believes the language in requirement R8 is still ambiguous and open-ended regarding, "... operations that result in, or could result in, an Emergency." It is unclear how entities are expected to determine events that could possibly happen. BPA suggests the drafting team include parameters for possible events, so applicable entities are not required to predict all possible future events. BPA also opposes language in the Standard which has the potential to conflate events that are happening with events that have a high probability of happening. BPA suggests the drafting team clearly separate these two concepts. Additionally, BPA disagrees with the change in R16 from "Real-Time Assessment" to "analysis". This is a very broad and, in this case, undefined term. BPA believes this could lead to differences in interpretation between a TOP and an auditor. For example, R16 applies to the Operations Planning Horizon. A study engineer's computer is part of an entity's analysis capability for doing studies in that horizon. Hence, as written, this requirement could be interpreted to mean that an entity's IT department would need to have System Operator approval prior to working on a study engineer's computer. BPA does not believe that was the drafting team's intent, but this broad language does leave that possible interpretation open.
Response: The definition of System Operating Limit is included in the NERC Glossary of Terms Used in Reliability Standards. By using the capitalized term, the requirements directly reference the defined term in the Glossary and are auditable. The SOL Exceedance White Paper is a guidance document and not intended to be part of a requirement. The paper outlines how the SDT interprets an		

Organization	Yes or No	Question 1 Comment
SOL exceedance to be determined and what to do when such occurs. The SDT believes that entities will be audited to Standards and Requirements that are referenced within the White Paper. The intent of the White Paper is to assist in providing a common understanding across the industry. No change made. The SDT believes that the language is correct as stated and consistent with the intent of the standards. If an entity performs an analysis and an Emergency situation is forecasted, then that entity should inform entities of this condition as per the requirement. An example could be the notification of an Emergency outage that would result in a known Stability issue requiring the execution of Operating Plans. No change made. The SDT has revised the wording of the requirement to provide additional clarity. See summary for language.		
Hydro One	No	Requirement R10 presents a significant concern. A Transmission Operator cannot be held responsible for monitoring in a neighboring Transmission Operator Area; a Transmission Operator can only rely on data provided by a neighboring area. If a Transmission Operator was responsible for monitoring in a neighboring area, what is the TOP monitoring, how, what are the available actions and obligations, should the actions be taken unilaterally?
Response: The SDT is not implying that an entity needs to establish monitoring capabilities such as its own RTU in another Transmission Operator's Area. In this requirement, monitoring outside of the Transmission Operator's Area means that a Transmission Operator is obtaining the data and presenting it to its operators as needed. For example, the Transmission Operator would obtain the status and MW flow on external facilities that are identified as having an impact on the Transmission Operators System Operating Limits. To provide clarification on this matter, the SDT has restructured the language of the requirement. See summary for language.		
Owensboro Municipal Utilities	No	The current language in TOP-001 R1 and R2 has further expanded the applicable use of operating instructions encompassing all individuals to the point where the compliance risk of the requirement is not appropriately weighted with the benefit to reliability. R3 and R4 state that only the registered entities identified must comply with OI; they do not state that registered entities identified are the only entities that can receive OI.

Organization	Yes or No	Question 1 Comment
		Therefore, without the lack of specificity in R1 and R2 (or in R3 and R4) to whom OI can be issued to, the standard now requires three point communication to any party or entity for actions that will affect the BES, even though that entity (unless identified in R3 and R4) does not have to comply. Although the NERC functional model states to whom a BA and TOP can direct, this is not referenced or mentioned in the standard, and must be inferred by not only the entity maintaining compliance, but also the individual performing an audit. It would seem very beneficial to specify this assumption within R1 and R2. Suggested Wording: R1 and R2: “Each Transmission Operator (Balancing Authority) shall act, or direct others (referenced in R3 and R4) to act by issuing Operating Instructions, to ensure the reliability of its Transmission Operator (Balancing Authority) Area.” In R10, replace “necessary” with “applicable” to maintain consistency with the definitions of Real-Time Assessment and Operational Planning Analysis. Suggested Wording: Each Transmission Operator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary applicable by the Transmission Operator, within its Transmission Operator Area and neighboring Transmission Operator Areas to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area In R13, the OC Review Group suggests expanding the time interval to 45 minutes instead of 30 minutes. When new EMS models are brought online, they may require greater than 30 minutes to perform an assessment. Either the time could be expanded or some sort of allowance provided for the times when the new models are being placed in service. In the R13 VSL, the OC Review Group suggests the time graduations for each level of VSL be retained (30-35 minutes, 30-40 minutes, 40-45 minutes, >45 minutes).

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		In R18, the OC Review Group suggests removing the word "always" before "operate" and provide graduated VSL to allow for when limits were determined to be incorrect due to mistake in entry of data. Suggested Wording: "R18: Each Transmission Operator and Balancing Authority shall always operate to the most limiting parameter in instances where there is a difference in SOLs." Should LSE be removed from applicable entities since LSE may be removed from the NERC Functional Model?

Response: The Functional Model is always implicitly part of any determination of how a requirement is written and is always a consideration in auditing a specific requirement. It is never explicitly cited in a requirement for those reasons. The SDT does not believe that the suggested change adds clarity or is necessary for reliability. No change made.

The SDT does not agree that 'necessary' should be replaced by 'applicable' in this requirement. The SDT believes that 'necessary' is the term that provides the proper context. No change made.

30 minutes is an approved time period for such requirements as seen in approved IRO-008-1, Requirement R2. The SDT has not received a preponderance of justification to change this previously approved time period. No change made.

The VSLs have been maintained.

The word 'always' is not used in Requirement R18. From reading the comment, it appears that the request is to add the term to the language. The SDT does not believe that this is necessary for reliability or that it provides any additional clarity. No change made.

The SDT believes that the VSL as currently stated is correct in its binary form. An entity should be operating to the most limiting set of limits with no exceptions. If the limits are incorrect, then an Operating Plan would be followed to adjust the limit until a new limit is analyzed and determined. No change made.

The SDT agrees that the Load-Serving Entity function may soon be deleted as the functions assigned to it are in the process of being retired or assigned to other functional entities. At its November 2014 meeting, the Board adopted the deletion of the Load-Serving Entity as a functional entity and a future filing with FERC will ask for approval of this action. Therefore, the SDT agrees to delete Load-Serving Entity from proposed TOP-001-3. See summary for language. However, there are two other standards in this project (Proposed TOP-003-3 and proposed IRO-010-2) that also contain the Load-Serving Entity as an applicable entity. Since those two standards have already passed ballot and been adopted by the Board, the SDT is not going to put the industry through the effort and

Organization	Yes or No	Question 1 Comment
burden of re-opening those standards at this time. When the retirement of Load-Serving Entity is adopted, there will be a project initiated to review all standards for the term and to make applicable deletions or replacements as needed. Those two standards will be picked up by that overarching project.		
Hydro-Quebec Production	No	Inclusion of NON-BES at R10 is inacceptable
New York State Department of Public Service	No	The requirement to monitor non-bulk facilities raises jurisdictional questions which needs to be settled before inclusion.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Flathead Electric Cooperative, Inc.	No	I continue to disagree with the level of detail in M3 and M4 for entities on the receiving end of a recorded instruction at the Transmission Operator/Balancing Authority level. Why should this have to be auditably demonstrated at both ends when everything is recorded upstream?
Response: The measures cited provide a list of things that could be supplied as evidence but there is no hard and fast requirement that voice recordings be supplied by both entities. An entity can make its own determination of whether it wants to maintain voice recordings or supply some other evidence for proof of compliance. No change made.		
Ameren	No	We have concerns on what constitutes "Operating Instructions", and over how an entity is supposed to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up

Organization	Yes or No	Question 1 Comment
		TOP's to an very burdensome way of documenting compliance. We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: "Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies." We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. Over the years the industry has clearly learned what a "Reliability Directive" means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able locate any such information in the Reliability Standard itself, nor does the standard give guidance on when there are no BES events for the period being audited.
Response: Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC's acceptance of the standards. No change made. The use of events in the RSAWs is designed to limit the scope of where an auditor should look for situations where these requirements may come into play. It should effectively reduce the amount of time where an auditor would be looking for evidence which should make an audit easier and more effective. In several locations, such as Measure M3, the SDT has addressed situations where no event may have occurred by allowing for attestations to that effect.		
NIPSCO	No	NIPSCO feels R19 and R20 should be in TOP-003 or are already covered in COM-001.

Organization	Yes or No	Question 1 Comment
		NIPSCO feels R16 and R17 are outage coordination and do not belong in TOP-001 which is Transmission Operations. These should be with the outage coordination standard.
Response: Approved COM-001-2 refers to voice communications and not data. Proposed TOP-003-3 defines operational reliability data specifications. FERC has made it clear in past transactions that data, in and of itself, is not sufficient for mandatory standards. There needs to be 'hardware' in place in order for the data to be exchanged and the SDT has written Requirements R19 and R20 accordingly. No change made. The proposed IRO-017-1 outage coordination standard is designed for Transmission and generation outages and coordination of same. Requirements R16 and R17 do not fit into that categorization and the SDT believes they are better suited to proposed TOP-001-3. No change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration L.P. ("ICLP") understands that FERC has ordered that TOPs and RCs must be able to monitor "non-BES" systems that they determine will affect System Operating Limits. However, it naturally follows that such important facilities must be part of the BES - and addressed in a far more formal way. It seems to ICLP that just such an exception process was created in NERC's Rules of Procedure when the Definition of the BES was modified. It allows the TOP/RC to make the case for the new addition - while the owner/operator has the opportunity to challenge it. Even if there needs to be an emergency bypass procedure to account for unexpected circumstances, at least a level of important control will exist. Otherwise, components and facilities can be essentially added to the BES without any recourse on the part of the affected entity. This raises the specter of the improper sharing of proprietary information and the chance of economic discrimination if such authority is misused. Secondly, a GOP will be expected to capture the fact that every Operating Instruction was performed unless it would "violate safety, equipment, regulatory, or statutory requirements." ICLP will execute in good faith to every instruction, but we are not confident that our log entries will be up to

Organization	Yes or No	Question 1 Comment
		auditor expectations - particularly if routine status or some other low-impact action is requested. The alternative offered by the project team (the RSAW only directs CEAs to review logs where a EOP-004-2 defined Event took place) is not binding. It is not hard to see that expectations will vary by Regional Entity and even change over time. Furthermore, the target of Operating Instructions will not be limited to BES Facilities. This could mean that as a Cogeneration Facility, we will be put into an untenable bind if ordered by a BA or TOP to re-direct capacity to the BES at the expense of our internal customer. Of course we are responsive to the needs of the greater system, but it should not be up to external entities to decide which needs take priority - keeping in mind that our installation is a critical part of the national chemical infrastructure.
Response: The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. Given the guidance provided to the auditor in the proposed RSAWs, BES events will be used by the auditor to constrain the potential amount of data an entity will need to provide. The SDT believes that this guidance is being provided in good faith and with the view that it will be used on a national basis. No change made. Nothing in this proposed standard exposes non-BES facilities to any requirement in any standard. The only obligations with regard to non-BES facilities is for data as documented in proposed TOP-003-3. No change made.		
Puget Sound Energy	No	The drafting team's revisions significantly improve the proposed standard. However, requirements R3 and R5 continue to impose a high compliance burden on entities that receive Operating Instructions. For example, a

Organization	Yes or No	Question 1 Comment
		Generator Operator could receive thousands of dispatch instructions each year. As the term is defined, each of these dispatch instructions would be an Operating Instruction and the GOP would be required to demonstrate that it complied with each of these Operating Instructions (or that it was unable to comply for the reasons specified in requirements R4 and R6). The standards drafting team for COM-002 recognized this issue when it developed a tiered approach for the communication protocols associated with Operating Instructions. The first tier requires an entity to periodically monitor compliance with its communications protocols and then correct issues that are discovered during this monitoring. The second tier requires entities to comply fully with its communication protocols during Emergency conditions only. This approach recognizes the importance of formal communications during both normal and Emergency conditions, but appropriately minimizes the compliance burden that would be associated with demonstrating compliance with an entity's communication protocols for all Operating Instructions. The drafting team should model that approach in this standard.
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency (IMPA) appreciates the hard work and effort the SDT has put into this standard. IMPA does not agree with using Operating Instructions within this standard. By using Operating Instructions within this standard, NERC has created an extremely administrative type of standard for entities to follow and to keep evidence to show they performed the Operating Instruction. This seems to be going in the opposite direction of what NERC is proposing in its RAI program with the theme of concentrating on the "risk" to the BES. IMPA acknowledges that the SDT writes the standard but also understands the influence NERC has on standard drafting teams. During high load times, an entity that has to follow its TOP's Operating Instructions will need to keep a good recording or log entry of the Operating Instruction and then proceed to keep documentation showing it was performed. Since the definition of an

Organization	Yes or No	Question 1 Comment
		Operating Instruction is vague and not clear, an entity will have to do this for every instruction from its TOP regardless of how they see the instruction because an auditor may view it as an Operating Instruction. For example, a Generator Operator will have to keep a log and evidence to show it performed the Operating Instruction for every start, stop, and load command for all of its generating units within its fleet (PJM is the TOP for many GOPs). IMPA recommends the drafting of requirements that allow entities to focus on the "risk" to the BES and not write requirements which are administrative in nature (meet paragraph 81 criteria).
Response: Given the guidance provided to the auditor in the proposed RSAWs, BES events will be used by the auditor to constrain the potential amount of data an entity will need to provide. The SDT believes that this guidance is being provided in good faith and with the view that it will be used on a national basis. No change made.		
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comment for consideration.1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define it when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed].R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions

Organization	Yes or No	Question 1 Comment
		cannot be performed].R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator...” R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority.”
Response: The SDT believes that it is counter to reliability to place a time tag on these requirements. The operator should be concentrating on the reliability issue and not be concerned with adhering to an arbitrary time period for informing entities. No change made.		
Independent Electricity System Operator	No	We generally agree with the changes made to the proposed TOP-001-3 standard, but continue to have a serious concerns over the proposed retirement of Requirement R4 of TOP-004-2 without having it reinstated in TOP-001-3 or having some of the requirements in TOP-001-3 revised to addressing the reliability need for confirming or reestablishing valid SOLs/IROLs in an unknown or unstudied state. We strongly believe that the Requirement R4 of TOP-004-2 addresses a critical reliability aspect that ensures the bulk electric system is operated in a reliable manner during real-time operations. And, if is not actually replaced by any new or revised requirement in TOP-001-3, it will create a reliability gap that is critical to the reliable operation of the bulk electric system. Requirement R4 of TOP-004-2 stipulates that: R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. In previous postings, we expressed a concern that by retiring R4 of TOP-004-2, the responsible entity (TOP in this case) will no longer be

Organization	Yes or No	Question 1 Comment
		required to reconfirm or reestablish valid SOLs or IROLs when entering an unknown (or unstudied) state. We recognize that by virtue of the proposed definition of Operational Planning Analysis (OPA) and Real-time Assessment (RTA), as well as the new requirement for TOPs to update their OPA results through the performance of a RTA every 30 minutes, that the entities will always be assessing the reliability of the BES. The SDT thus argues that this, together with the TOP-001-3 Requirements R12, R13, and R14, will allow the operators sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System and hence Requirement R4 of TOP-004-2 can be retired. We continue to disagree with the SDT's rationale for retiring R4 of TOP-001-3. Below is our point by point comment on the SDT's response to our last round of comment. This is not meant to be a criticism of the SDT's response. Rather, we choose to present our comment in this manner so that we can more clearly present our view on each of the technical arguments that the SDT made. a. The SDT [believes the existing requirements within the standard to perform a Real-time Assessment include reevaluation of SOL/IROL limits to either reestablish new limits or implement Operating Plans to stay within updated limits. The SDT does not believe that the proposed requirements and standards allow an entity to be in an unknown state consistent with established IROL Tv.] The IESO believes that an unknown state is one which has not been assessed before in IROL or SOL calculation or reliability assessment, and therefore there does not exist an updated, valid limit until it is re-determined (or reconfirmed). We further believe that the SDT's view that "by complying with the proposed requirement, an entity will never enter into an unknown state" may be an oversimplified assumption, if not an oversight. An unknown operating state includes an unstudied state beyond those which the calculated SOLs or IROLs are intended to cover. b. [The premise of the SDT's philosophy is that an Operational Planning Analysis must be available for next day and that this analysis must be periodically

Organization	Yes or No	Question 1 Comment
		updated by performing a Real-time Assessment as per proposed TOP-001-4 Requirement R13.]The IESO believes that the OPA and RTA are good tolls, but they only look ahead at anticipated conditions and assess real-time situation in response to system changes and by themselves they are not a limit calculation mechanisms. Therefore, while these tasks will aid in assessing performance of the system against established limits, such limits may not exist; and OPA and RTA are not the tasks to calculate limits for the anticipated or prevailing conditions, especially for the stability restricted SOLs/IROLs. c. [Both of these functions require an established set of Facility Ratings be in use so that analysis can discern when these limits are being exceeded. It is the SDT's belief that once these limits have been established that it does not matter what event occurs to cause an exceedance.]The IESO believes that this may be true for facility limited SOLs/IROLs, but not for voltage and/or stability restricted SOLs/IROLs. d. [The event takes place and is analyzed against the set of limits currently in place.]The IESO believes that a set of valid limit (voltage and stability limited type) may not exist for conditions that have not been studied and therefore there is no such "set of limits currently in place". e. [It is these limits that an entity must restore the system to following the event as per proposed TOP-001-4 Requirement R14.]This is achievable if the limits already exist. But when the limits do not exist, as in the case of SOLs or IROLs that are restricted by stability and when the prevailing conditions are ones that have not been studied before, there is not a target (SOL or IROL) with which the system is to be restored to. f. [Therefore, the SDT believes that approved TOP-004-2 Requirement R4 can be retired without creating a reliability gap. The SDT recognizes that not all entities are capable of performing Real-time transient Stability analysis within 30 minutes and would rely on Operating Plans. No change made. The IESO believes that an Operating Plan is only a plan for the anticipated conditions. Changes during real-time operation can render the assumptions and pre-determined limits invalid and hence the responsible

Organization	Yes or No	Question 1 Comment
		entity cannot rely on the Operating Plan to provide SOLs/IROLs that are stability restricted. We agree that with the current technology, it is doubtful if any entities can rely on real-time tools to calculate SOLs/IROLs in 30 minutes. However, this should not be a reason to not reestablish SOLs/IROLs when an entity encounters a condition that is "unknown" or not studied before. There are various means to achieve such tasks, but a necessary first step to ensure entities reestablish valid SOLs/IROLs is to stipulate this in a standard. Retiring R4 of TOP-004-2 will do just the opposite: responsible entities will not be mandated to reestablish valid limits to begin with when entering an unstudied or unknown state. We once again urge the SDT to reinsert R4 of TOP-004-2 to TOP-001-3, or to expand Requirement R13 to require TOPs to reestablish valid SOLs when the prevailing conditions are beyond those that are covered by or have been studied in SOL calculations.
Response: The SDT understands the concern of moving to an unknown state which it interprets as a condition that has not been previously studied. However, the SDT believes that there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to a unplanned system event. No change made.		
NV Energy	No	The comments of NV Energy, particularly with regard to requirement R13, remain unaddressed in this latest posting. We continue to urge the SDT to depart from the zero defect approach on the language of R13. It seems unreasonable to expect perfect execution of the suggested real-time analyses, including the provisions for incorporation of the elements of SPS/RAS and protection system status, 17,520 times per year. By the SDT's

Organization	Yes or No	Question 1 Comment
		own response to NV Energy's comments in the prior ballot/comment period " This requirement isn't about maintaining RTCA or any other specific tool, it's about maintaining situational awareness at all times." Yet the SDT nevertheless declined to make any change to the language of R13. We continue to believe that the language suggested below is reasonable given the complexity of the requirements of TOP-001-3. We therefore suggest the following: R13: "Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP."
Response: The SDT has reviewed the suggested language change to Requirement R13 and concluded that the proposal presents ambiguity and is not measurable. Proposed IRO-008-1, Requirement R2 currently requires the Reliability Coordinator to conduct a Real-time Assessment at least once every 30 minutes. Approved EOP-008-1 specifically requires entities to have capabilities to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. The SDT developed proposed TOP-001-3, Requirement R13 to be consistent with the intent of existing requirements. Proposed TOP-001-3, Requirement R13 has been previously modified to reflect industry comment in order to recognize that other entities may perform Real-time Assessment during EOP-008 scenarios. No change made.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and impacted interconnected entities of sustained outages of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor's suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of sustained outages of telemetering

Organization	Yes or No	Question 1 Comment
		and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States:R10. Each Transmission Operator shall monitor the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.2. Within neighboring Transmission Operator Areas identified as necessary by the Transmission Operator:10.2.1. Facilities,10.2.2. Status of Special Protection Systems, and10.2.3. Non-BES facilities. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R1O.2, R10.2.1., R10.2.2 and R10.2.3 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.

Organization	Yes or No	Question 1 Comment
Response: The SDT removed the term 'negatively impacted' due to comments in a previous posting. The logic was that an entity would not be positively impacted by an outage so the term was redundant. No change made. The SDT believes that sufficient flexibility is provided in the revised language for Requirement R10. How an entity accomplishes the task is not in scope for standards. If there are lower cost alternatives available that meet the goal of the requirement, they may be used. In the situation cited, data exchanges will already be in place, or will need to be installed, to comply with other requirements such as proposed TOP-003-3, Requirement R5. Therefore, given the revised language, the SDT does not see any undue burden, financial or otherwise, to comply with this requirement. No change made. IROLs are, and always have been, determined by the Reliability Coordinator as per the approved FAC-011 and FAC-014 standards and passed along to Transmission Operators. T_v is part of this methodology. Whether multiple Transmission Operators are involved or not has no relevance as they must all adhere to what is provided by the Reliability Coordinator. No change made.		
Georgia Transmission Corporation	No	(1) GTC requests the drafting team remove the DP and LSE designation from Requirements R3 and R5 and develop separate requirements for the DP and LSE to comply with Operating Instructions to shed or shift load. By making this change, the requirements could be made clearer that the Operating Instructions that the DP and LSE receive from the TOP with respect to the defined term Operating Instruction, correspond to "impacting" the output of an Element of the BES (shed or shift load). Because the term Operating Instruction is tied to the BES, a standalone requirement is necessary to eliminate the ambiguity associated with entities with multiple registrations such as TOs who are also DP/LSE's that own BES equipment. It should be noted that this Standard does not apply to a Transmission Owner, but the field personnel who perform switching in substations of entities with both registration types are typically the same personnel. The level of Operating Instructions performed for multiple registration type (TO/DP/LSE) entities would be much more voluminous and burdensome due to the ownership of transmission equipment than the typical DP/LSE type entities for the same requirement. GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP/LSE dispatch center that

Organization	Yes or No	Question 1 Comment
		does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). GTC urges the drafting team to consider this additional exposure of field personnel of TO/DP entities that switch in transmission substations to which the standard does not apply. Per discussions with Standard Drafting Team members and industry personnel, the scenario for DP/LSE's to receive Operating Instructions are limited to load shed or shift scenarios to preserve the reliability of the BES by the defined term associated with "impacting" the output of an Element of the BES. Exposing these multiple registration type entities to a set of mandatory standard requirements to which they do not apply such as those TOs and DPs identified above, demonstrates the potential flaw with the current language. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: o Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Transmission Operator to shed or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. o Each Distribution Provider and Load Serving Entity shall comply with each Operating Instruction issued by its Balancing Authority to shed load or shift load, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) Please note that M1 should be changed from "ensure" to "address" to match R1. (3) Part 10.1.3 and 10.2.3's reference to "Non-BES facilities" is outside the scope of reliability standards. Reliability standards are applicable to the BES, which would be Facilities. Refer to NERC's memo dated April 10, 2012 with respect to use of the term BES in Reliability Standards. The revised BES definition addresses Elements and Facilities that should be subject to the reliability standards through the BES exception process. Although the TOP will monitor Non-BES facilities in practice, there is no reason to include non-

Organization	Yes or No	Question 1 Comment
		BES Elements in the requirement subject to mandatory enforcement. Parts 10.1.3 and 10.2.3 that reference “non-BES facilities” should be struck.
Response: 1) Functional Model v5 determines what entities a Transmission Operator or Balancing Authority can issue Operating Instructions to and what those Operating Instructions can contain. Furthermore, the SDT believes that it would be counter-productive to set up individual requirements for entities that address specific types of operating Instructions. The resultant standard would be voluminous and impossible to understand. No change made. 2) The SDT has corrected the Measure. 3) The SDT has made several changes to the language of the requirement for clarity. Requirement R10, Parts 10.1.3 and 10.2.3 have been deleted. The SDT believes that non-BES facilities are already handled in the Reliability Standards. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in Requirement R10, Parts 10.1 and 10.2 by use of the defined term ‘Facilities’. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology.		
Liberty Electric Power	No	The standard does not contain a requirement for the TO to identify the Operating Instruction as a reliablity instruction as opposed to a market instruction.
Response: Operating Instruction is a defined term and is used in this standard in that context. No change made.		
Manitoba Hydro	No	Manitoba Hydro agrees with changing the term “ensure” to “address” throughout the standard, however in M1 the term “ensure” remains even though its associated requirement R1 has “address”. We believe the intent was to replace “ensure” with “address” as it is in M2. In Pages 15 and 16 of TOP-001-3, Table of Compliance Elements, “Operations Planning” in the Time Horizon column of R1 through R6 should be deleted because they were deleted in Requirements R1 through R6.

Organization	Yes or No	Question 1 Comment
Response: The SDT has corrected Measure M1. This change was already made in the previously posted version. No change made.		
Lincoln Electric System	No	For smaller entities that do not own or operate a state estimator, the Real-time Assessment required in R13 would be overly burdensome, if not impossible, to meet internally. Although the drafting team indicates a third-party service may be utilized in lieu of an internal system, smaller entities would be wholly reliant on a third-party in order to maintain compliance with R13. This is of particular concern when considering that if a Protection System status were to change unexpectedly on a smaller entity's system, that entity would be expected to notify a third-party and then have that third-party perform a modified contingency analysis, pending availability, all within 30 minutes. Rather than treat all TOPs the same without consideration for size or risk to the BES, recommend that, at a minimum, the timeframe for conducting the Real-time Assessments be expanded or else allow the individual TOPs to establish the timeframe.
Response: The suggested language change to Requirement R13 presents ambiguity and is not measurable. There are many different ways for an entity to perform a Real-time Assessment. A small entity may be able to come up with any number of suitable methods that would not involve using Real-time Contingency Analysis. For example, the Reliability Coordinator or adjacent Transmission Operators could provide this service and data links should already be in place with these entities to comply with other requirements. No change made.		
CenterPoint Energy Houston Electric LLC	No	R1. - CenterPoint Energy agrees with the addition of "...direct actions or by issuing Operating Instructions" as well as using 'address' rather than 'ensure', however CenterPoint Energy prefers the manner in which the previous R1 was drafted. CenterPoint Energy suggests the following language: "Each Transmission Operator shall take direct actions or issue Operating Instructions to address the reliability of its Transmission Operator Area."

Organization	Yes or No	Question 1 Comment
		R10.2 - CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the Reliability Coordinator’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. - CenterPoint Energy agrees that a Real-Time Assessment (RTA) should be run every 30 minutes, however the Company is concerned that events could occur that are outside of the Transmission Operator's control (Ex. Loss of ICCP data) that may prevent the Transmission Operator from performing a RTA as required; therefore there should be a caveat as to when exceeding the 30 minutes is allowed. CenterPoint Energy recommends the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality. R14. - CenterPoint Energy suggests changing Operating Plan to Operating Plan(s).
Response: Requirement R1 has been changed due to comments received to provide additional clarity. See summary for language.		

Organization	Yes or No	Question 1 Comment
The SDT has changed the language of the requirement due to comments received. See summary for language. The SDT has clarified what it intended by monitoring in the revised language. The SDT believes that the suggested language is unnecessary. Obviously, a Transmission Operator is going to work as quickly as possible to restore functionality as it is in its best interests to do so. Loss of ICCP data is a major concern. Other standards point to redundancy for these situations that could alleviate the concern. Approved EOP-008-1, Requirement R1, Part 1.6.2 deals with what needs to happen due to loss of functionality. That requirement states that an entity is still responsible for managing the risk during such a situation. The SDT believes that ensuring that a Real-time Assessment is performed at least once every 30 minutes is not unrealistic or overly burdensome in today's operating environment. This is also consistent with approved IRO-008-1, Requirement R2. No change made. The SDT believes that the inclusion of guidance on what an Operating Plan should be in this situation as shown in Section F addresses the concern. No change made.		
HHWP	No	R16 states: "Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its monitoring, telecommunication, and analysis capabilities." Organizations should be free to designate its preferred method for approving planned outages of data equipment. This requirement imposes on all TOPs single process for data system outage approval. The requirement should be results based on not proscriptive of the method to achieve those results. This is a huge step backwards in the development of rational reliability requirements.
Response: The SDT believes that the requirement is written with sufficient flexibility to allow an entity to determine how to implement it and does not see how the requirement is overly prescriptive. The measure for this requirement does not specify a particular process or solution. No change made.		
American Transmission Company, LLC	Yes	ATC agrees with the changes to the proposed TOP-001-3, however, ATC recommends that Requirement R9 be modified by replacing "sustained" with "planned or sustained." This modification will provide clarity to the

Organization	Yes or No	Question 1 Comment
		requirement and align with comments made by the SDT during the October 16th TOP/IRO webinar that planned outages were in view.
Response: The SDT agrees that a change is required and has modified the language accordingly. See summary for language.		
Tri-State Generation and Transmission Association, Inc.	Yes	There was the addition of "sustained" for clarification in requirement R9. Tri-State wonders if the SDT meant to use the defined term "Sustained Outage" in this requirement or if they did not intend to use that defined term?
Response: The SDT did not intend to use the defined term, thus the lack of capitalization. The defined term applies only to Transmission outages which is not the condition here. The SDT has added a time element to the requirement language based on received comments. See summary for language.		
Central Lincoln People's Utility District		Central Lincoln recently participated in a load shedding drill led by our Host BA/TOP. The single most glaring problem we saw was one of validation. In the past we had always thought we would validate an R3 Directive or Operating Instruction by calling the TOP back at a known phone number. Our TOP informed us that such a validation method would not be possible during a real event, since all phones and switchboards would likely be busy. While objecting to our validation method, the TOP has failed to offer a suitable one. This leaves Central Lincoln with the choice of responding to an Operating Instruction to shed load coming from a scammer who has easy access TOP-001 on line, or risking a possible violation. Suggest the SDT begin looking at the question of validation, since without a validation method R3 poses a greater risk to reliability than it addresses.
Response: Communications is a concern for COM standards. For operating standards, such as the TOP standards, communication is considered to already be in place. The SDT suggests working with your Transmission Operator and Reliability Coordinator to work toward an acceptable resolution. Multiple technology options exist to address your concern. No change made.		

Organization	Yes or No	Question 1 Comment
DTE Electric Co.	Yes	We support the changes and have no concerns/comments to add.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
American Electric Power	Yes	
South Carolina Electric & Gas	Yes	

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Third posting October 10, 2014 to November 10, 2014

Proposed Action Plan and Description of Current Draft

This is the fourth posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
Presentation to the NERC Board of Trustees for adoption	January 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**

    4.1. Balancing Authority

    4.2. Transmission Operator

    4.3. Generator Operator

    4.4. Distribution Provider

    4.5.

5. **Effective Date:**

    See Implementation Plan.

6. **Background:**

    See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating

Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. 'This changes is in response to the Independent Experts Review Panel (IERP) recommendations. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic

communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_V. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and R15 through R20 and Measure M1 through M11, and M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform one known	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform two known	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more,	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R11	Real-Time Operations	High	N/A	N/A	The Balancing Authority did not monitor the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

URL for SOL Exceedance White Paper to be placed here when final location is available.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator’s disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Third posting October 10, 2014 to November 10, 2014

Proposed Action Plan and Description of Current Draft

This is the ~~third~~fourth posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	~~October~~January 2014
Presentation to the NERC Board of Trustees for adoption~~BOT~~	~~November~~January 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by ~~BOT~~ Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Transmission Operator
   4.3. Generator Operator
   4.4. Distribution Provider
   4.5. ~~Load-Serving Entity~~
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act to ~~address~~maintain the reliability of its Transmission Operator Area via ~~direct~~its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to ~~ensure~~maintain the reliability of its Transmission Operator Area via ~~direct~~its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to ~~address~~maintain the reliability of its Balancing Authority Area via ~~direct~~its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to ~~address~~maintain the reliability of its Balancing Authority Area via ~~direct~~its own actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider~~, or Load-Serving Entity~~ may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall inform its Transmission Operator of its inability to ~~perform~~comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider~~, or Load-Serving Entity~~ may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall make available upon request, evidence that it complied with each Operating Instruction issued by the Balancing Authority(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider~~, or Load-Serving Entity~~ may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall inform its Balancing Authority of its inability to ~~perform~~comply with an Operating Instruction issued by that Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider~~, or Load-Serving Entity~~ may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. '~~Comparable' deleted as it is impossible to measure comparability and the main concept is that the originating entity has implemented its emergency procedures.~~ Th~~ese~~is changes ~~are~~is in response to the Independent Experts Review Panel (IERP) recommendations. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting ~~entity~~Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance ~~cannot~~could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic

communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no ~~Emergency has~~such situations have occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15. ~~The term 'sustained' was added to the requirement to indicate that notification is not required for momentary events.~~

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned ~~sustained~~ outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned ~~sustained~~ outages of 30 ~~continuous~~ minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall ~~monitor~~~~do~~perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems~~:~~, and

~~Facilities,~~

~~The status of Special Protection Systems, and~~

~~Non-BES facilities identified as necessary by the Transmission Operator and~~

10.2. ~~Within neighboring~~Outside its Transmission Operator Area,~~s identified as necessary by the Transmission Operator~~ obtain and utilize status, voltages, and flow data for Facilities and the s~~S~~tatus of Special Protection Systems.~~:~~

~~Facilities,~~

~~Status of Special Protection Systems, and~~

~~Non-BES facilities.~~

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitor~~s~~ed or obtained and utilized status, voltages, and flow data for Facilities~~,~~ and the status of Special Protection Systems~~, and non-BES facilities~~ as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order ~~for it~~ to maintain ~~be able to perform its reliability functions~~ Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management ~~s~~System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order ~~for it~~ to ~~be able to perform its reliability functions~~ maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it ~~has~~ operated outside any identified Interconnection Reliability Operating Limit (IROL), ~~for a~~the continuous duration did not exceed~~ing~~ its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time ~~-~~Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the ~~s~~System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the ~~s~~System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its ~~monitoring, telecommunication, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of ~~its monitoring, telecommunication, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its ~~monitoring, telecommunications, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its ~~monitoring, telecommunications, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider~~, and Load-Serving Entity~~ shall each keep data or evidence for each applicable Requirement R1 through R11, and R1~~4~~5 through R20 and Measure M1 through M11, and M1~~4~~5 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall ~~each~~ keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider~~, or Load-Serving Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to ~~address~~maintain the reliability of its Transmission Operator Area via ~~direct~~its own actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to ~~address~~maintain the reliability of its Balancing Authority Area via ~~direct~~its own actions or by issuing Operating Instructions.
R3	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to ~~perform~~comply with an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Operating Instruction issued by its Transmission Operator.
R5	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to ~~perform~~comply with an Operating Instruction issued by that Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						safety, equipment, regulatory, or statutory requirements.
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR,	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR,	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted other Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas when conditions did permit such communications. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more ~~other~~ known impacted Transmission Operators or more than 15% of the known impacted ~~other~~ Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas when conditions did permit such communications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	The Transmission Operator did not inform two known impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.	OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas when conditions did permit such communications.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known ~~negatively~~ impacted entities, whichever is greater, of a planned outage, or an	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known ~~negatively~~ impacted entities, whichever is greater,	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known ~~negatively~~ impacted entities, whichever is greater, of a planned	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned ~~sustained~~ outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			unplanned ~~sustained~~ outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, ~~and~~or associated communication channels between the affected entities.	of a planned outage, or an unplanned ~~sustained~~ outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, ~~and~~or associated communication channels between the affected entities.	outage, or an unplanned ~~sustained~~ outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, ~~and~~or associated communication channels between the affected entities.	associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known ~~negatively~~ impacted ~~NERC registered~~ entities, whichever is greater, of a planned outage, or an unplanned ~~sustained~~ outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, ~~and~~or associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not ~~monitor~~ obtain and	~~The Transmission Operator did not monitor two of the items listed in Requirement R10, Part 10.1.~~ ~~OR,~~ ~~The Transmission Operator did not monitor two of the~~	The Transmission Operator did not monitor Facilities~~,~~ and the status of Special Protection Systems~~, and non-BES facilities~~ within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize one of the items listed in Requirement R10, Part 10.2.	~~items listed in Requirement R10, Part 10.2.~~ The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	
R11	Real-Time Operations	High	N/A	N/A	~~N/A~~ The Balancing Authority did not monitor the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, ~~including the status of Special Protection Systems that impact generation or Load,~~ in order ~~for it~~ to ~~be able to perform its reliability functions~~ maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the ~~s~~System to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations, Real-Time Operations					to approve planned outages and maintenance of its ~~monitoring, telecommunication, and analysis capabilities~~ Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its ~~monitoring, telecommunications, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-Time Operations					and maintenance of its ~~monitoring, telecommunications, and analysis capabilities~~ Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its ~~monitoring, telecommunications, and analysis capabilities~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	Operations Planning, Same-Day Operations,	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with two identified entit~~y~~ies, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with three identified entit~~y~~ies, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entit~~y~~ies, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entit~~y~~ies, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~White paper on SOL Exceedances to be placed here. (or URL to be supplied)~~ URL for SOL Exceedance White Paper to be placed here when final location is available.

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**
    - TOP-001-1a Reliability Responsibilities and Authorities
    - TOP-002—2.1b Normal Operations Planning
    - TOP-003-1 Planned Outage Coordination
    - TOP-004-2 Transmission Operations
    - TOP-005-2a Operational Reliability Information
    - TOP-006-2 Monitoring System Conditions
    - TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
    - TOP-008-1 Response to Transmission Limit Violations
    - IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
    - IRO-002-2 Reliability Coordination — Facilities
    - IRO-003-2 Reliability Coordination – Wide Area View
    - IRO-004-2 Reliability Coordination – Operations Planning
    - IRO-005-3.1a Reliability Coordination — Current Day Operations
    - IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
    - IRO-010-1a Reliability Coordinator Data Specification and Collection
    - IRO-014-1 Coordination Among Reliability Coordinators
    - IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
    - IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
    - PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project. Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:
    - TOP-001-2 Transmission Operations
    - TOP-002-3 Operations Planning
    - TOP-003-2 Operational Reliability Data
    - IRO-001-3 Reliability Coordination - Responsibilities and Authorities
    - IRO-002-3 Reliability Coordination — Analysis Tools
    - IRO-005-4 Reliability Coordination — Current Day Operations
    - IRO-014-2 Coordination Among Reliability Coordinators
    - PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the currently enforceable standards and definitions would remain effective until those approvals have occurred, and the new or revised standards in Project 2014-03 shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective three months earlier, in order to provide recipients of data requests from their Reliability Coordinators, Transmission Operators, and/or Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. **If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:**
    - **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
      The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

    - **For proposed TOP-003-3:**
      All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

      Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

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RELIABILITY CORPORATION

Unofficial Comment Form

Project 2014-03 Revisions to TOP/IRO Reliability Standards
TOP-001-3

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **8 p.m. Eastern, January 7, 2015**.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Additional information about this project is available on the project page.

Background Information - Project 2014-03 – Revisions to TOP/IRO Reliability Standards

On November 21, 2013, FERC issued a NOPR proposing to remand three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards and four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) to replace six currently-effective IRO standards. In the NOPR, FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."

In response, NERC filed a motion requesting that FERC defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process. That motion to defer action was granted on January 14, 2014.

The drafting team formed to address those concerns has made revisions to the TOP and IRO standards proposed to be remanded, along with several other IRO standards to provide consistency amongst the TOP and IRO standards, to address NOPR issues and recommendations made by the Independent Expert Review Panel, the IRO five-year review team (FYRT), and the 2011 SW Outage Report. In the ballot that ended September 19, 2014, all of the standards except TOP-001-3 achieved greater than the required two thirds ballot pool approval. The SDT has reviewed stakeholder comments submitted in that comment period and made only clarifying and non-substantive changes to all of the standards except TOP-001. No changes were made to the definitions or implementation plan.

The SDT has made numerous changes in the fourth posting for proposed TOP-001-3 in order to respond to industry comments raised in the third posting.

- Requirement R1 – removed the ‘direct action’ language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced ‘address’ with ‘maintain’. .
- Requirement R2 - removed the ‘direct action’ language to alleviate concerns about potential double jeopardy issues as direct actions are included in other standards and requirements where necessary; replaced ‘address’ with ‘maintain’.
- Requirements R3, R4, R5, and R6 – removed the Load-Serving Entity as an applicable entity following the recent Board action on removing Load-Serving Entity as a functional entity. (Note – Load-Serving Entity was not removed from proposed IRO-010-2 or proposed TOP-003-3 as those standards have already been approved by industry and the Board. Load-Serving Entity will be removed from those standards when the overarching project to remove Load-Serving Entity is initiated.)
- Requirement R7 – Added the phrases ‘within its Reliability Coordinator Area’ (as Transmission Operators will only be expected to react to requests from other Transmission Operators within the Reliability Coordinator Area and any assistance for Transmission Operator Areas outside the Reliability Coordinator Area will be done through requests from the Reliability Coordinators) and ‘comparable’ assistance (to assure that a transmission Operator isn’t asked to do go further than the requesting Transmission Operator has done).
- Requirement R9 – added ‘known’ as a qualifier for impacted entities; clarified that the requirement is for all outages by adding ‘planned and unplanned’ as qualifiers to outages; replaced ‘sustained’ by ’30 minutes or more’ to achieve clarity and consistency with other standards.
- Requirement R10 – deleted the phrase ‘non-BES’ as any need for non-BES data will be defined in the Reliability Coordinator SOL methodology and included in BES as part of BES Exception Process as necessary; clarified that an entity does not have to ‘monitor’ outside of its Transmission Operator Area – it only needs to utilize necessary data.
- Requirement R11 – replaced the phrase ‘perform its reliability functions’ with more specific language – ‘maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency’.
- Requirement R15 – capitalized ‘System’
- Requirement R16 – made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Requirement R17 - made the language for the list of applicable outages consistent with that of the language in Requirement R9.
- Made commensurate changes in matching Measures and cleaned up language in Measures M8 and M12.
- Made commensurate changes to VSL language and changed the VSL for Requirement R11 from binary to incremental.
- Added language to the SOL Exceedance White Paper explaining that the Reliability Coordinator’s SOL methodology will specify requirements to include any non-BES data or external data in order for a Transmission Operator to determine SOLs in accordance with the Reliability Coordinator’s SOL methodology.

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Commenters are reminded that this is not a forum for questioning the issues raised in the FERC NOPR of November 21, 2013 but to objectively evaluate the work of the SDT in responding to the issues raised in the NOPR, and the recommendations made by the Independent Expert Review Panel (IERP), the IRO FYRT, and the SW Outage Report.

Questions

1. Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

Notice of Request to Waive the Standard Process

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

As required by Section 16 of the NERC Standard Processes Manual (SPM), this is official notice to stakeholders that the leadership of the Project 2014-03 Revisions to TOP and IRO Reliability Standards Drafting Team, the Project Management Oversight Subcommittee (PMOS) liaison for that project, Standards Committee (SC) chair, and NERC Standards Staff (Requesters) are requesting that the SC consider a waiver of the Standard Processes Manual. The Requesters ask to shorten the next formal comment and ballot period for draft standard TOP-001-3, and any subsequent comment formal comment and ballot periods prior to final ballot for that standard, from 45 days to 30 days, and to shorten the final ballot for TOP-001-3 from ten days to seven days, in order to meet a regulatory deadline. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process.

The SC will meet via teleconference to consider this waiver request no earlier than Thursday, October 9, 2014 (to comply with the five business day notice required by Section 16 of the SPM). The Standards Committee's teleconference will be noticed through an announcement and posted on the NERC website. Additional details about the waiver request are included below, and should a waiver be granted by the SC, it will be posted on the project page.

Justification for Current Waiver Request

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) proposing to remand three revised TOP Reliability Standards and four revised IRO Reliability Standards. In the NOPR FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed

TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

NERC's motion to defer action was granted on January 14, 2014.

The drafting team has developed a set of eight revised standards and one new standard to replace the standards that the NOPR proposed to remand. The standards have been posted for two 45-day comment periods and ballots, and in the ballot ending September 19, 2014, eight of the nine standards achieved greater than the required two-thirds weighted segment approval.

The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Laura Hussey,
Director of Standards Development, at laura.hussey@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Waiver Authorization for Project 2014-03: Revisions to TOP and IRO Reliability Standards

Action

Authorize a waiver of the Standard Processes Manual (SPM) to:

a) shorten the next additional formal comment period (and any subsequent additional formal comment periods) for draft standard TOP-001-3 from 45 days to 30 days, with a ballot and non-binding poll during the last seven days of the 30 day period; and

b) shorten the final ballot period from ten days to seven days.

Background

The leadership of the TOP/IRO Standard Drafting Team, NERC staff, and the PMOS liaison and Standards Committee (SC) chair have requested a waiver of the NERC Standards Processes Manual (SPM) as described in the actions above. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process. As required in Section 16, NERC provided stakeholders with notice of these waiver requests on October 2, 2014. If a waiver is authorized, NERC staff will post notice of the waiver on the project page and notify the NERC Board of Trustees Standards Oversight and Technology Committee.

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) proposing to remand three revised TOP Reliability Standards and four revised IRO Reliability Standards. In the NOPR FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

NERC's motion to defer action was granted on January 14, 2014.

The drafting team has developed a set of eight revised standards and one new standard to replace the standards that the NOPR proposed to remand. The standards have been posted for two 45-day comment periods and ballots, and in the ballot ending September 19, 2014, eight of the nine standards achieved greater than the required two-thirds weighted segment approval.

The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to: Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information

Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):

Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06.

If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well.

In addition, the recommendations from the Independent Expert Review Project and the SW Outage Report will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT shall:

1. Revise the TOP/IRO Reliability Standards to address concerns expressed in the NOPR
    a. Consider the inputs from technical conferences
2. Consider the recommendations in the Independent Expert Review Report and the SW Outage Report
3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards)
4. Preserve the intent of the reliability objectives in the current, approved standards so that no reliability gaps are created
5. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02.
6. Address the directives from Order 693 originally assigned to Projects 2006-06 and 2007-03.

SAR Information
7. Address the following directive from Order 693, paragraph 1855: *“Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator’s monitoring responsibilities*.” 8. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements. 9. Address the issue of outage coordination as pointed out by the Independent Experts Review Panel through the creation of a new standard. 10. Address the recommendations of the IRO Five Year Review Team (Project 2012-09) for the IRO standards revised in this project.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.

Reliability Functions	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒ Distribution Provider	Delivers electrical energy to the End-use customer.
☒ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	**Explanation**
IRO-003-2 IRO-004-2 IRO-006-5 IRO-008-1 IRO-009-1 IRO-010-1a IRO-015-1 IRO-016-1	May need to be reviewed for language and terminology consistency with revisions made in this project.

Related SARs	
SAR ID	**Explanation**
N/A	N/A

Regional Variances	
Region	**Explanation**
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A

Regional Variances	
SPP	N/A
WECC	N/A

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | Updated December 2014

This mapping document showing the translation of Requirements in the following currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions[1]
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

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[1] TOP-006-2 is the currently enforceable version of this standard; TOP-006-3 was developed in response to a request for interpretation seeking clarification of Requirement R1 and does not substantively change the Requirements of TOP-006-2. In its NOPR proposing to remand the TOP and IRO standard, FERC proposed to approve TOP-006-3. The drafting team has mapped the Requirements in the new standards to TOP-006-3 because the Parts of Requirement R1 in TOP-006-3 more clearly delineate which entity has responsibility.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** "Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4)." **Section 501 (1.4)** "**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority."
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** The SDT proposes retiring Requirement R2 as the regional reliability plan is a high level overview "how" document that shows how a Reliability Coordinator will comply with other NERC Standards. As a result, this requirement is administrative and redundant to other measureable and enforceable requirements within the standards. Since the requirement is generally administrative, it does not materially impact the reliability of the BES. The Reliability Plan concept is a holdover from the transition period from the Operating Policies to the Version 0 standards and was used extensively in the readiness evaluation process by the Operating Committee. The template used for the Reliability Plan is actually an outline of Operating Policy 9. The material included in the plan was a description of how an entity satisfied the specific functional areas under Policy 9. With the transition of Policy 9 to the IRO and other standards, the items addressed in

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	the reliability plans are inherently addressed in the body of other more measurable Reliability Standards.
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or by issuing Operating Instructions. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3. **Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator may implement alternate remedial actions.	
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed COM-001-2 Requirement R1 for voice links and proposed IRO-002-2 Requirement R1 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed COM-001-2, Requirement R1:** **R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R1:** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Approved PER-004-2, Requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, Part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, Part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability	This requirement is replaced by proposed COM-001-2 Requirement R1 and proposed IRO-002-4 Requirement R2. **Proposed COM-001-2, Requirement R1:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	**R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R2:** **R2**. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirements R3 and R4:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to	This requirement is replaced by proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R4:** **R4**. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R3 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have	This requirement is replaced by proposed IRO-002, Requirement R2 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R2:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
procedures in place to mitigate the effects of analysis tool outages.	**R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunications, monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R3 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	This requirement is replaced by proposed IRO-001-4, Requirement R1 since Operating Instructions, regardless of what timeframe they are issued for, are issued in a Real-time environment. In addition, roles for entities identified in the Operating Plans built from Operational Planning Analyses are communicated in proposed IRO-008-2, Requirement R3. **Proposed IRO-001-4, Requirement R1:** R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed IRO-008-2, Requirement R3:** R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s).

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	Replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and	The first sentence is replaced by proposed IRO-002-4, Requirement R3. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R3**:

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by approved EOP-010-1, Requirements R1 through R3. **Approved EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R3, R5 and R6. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-34 Requirements R3 and R4. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-010-2, Requirements R1, Part 1.2, and R3.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	**Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-010-4, Requirement R1, Part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses; **2.1.4.** Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall	The requirement is replaced by proposed IRO-008-2, Requirements R3, R5, and R6. **Proposed IRO-008-2, Requirement R3:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	**R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R4. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R3 and R5. **Proposed IRO-008-2, Requirements R3 and R5:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, R6:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: **R1.1.** List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. **R1.2.** Mutually agreeable format. **R1.3.** Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). **R1.4.** Process for data provision when automated Real-Time system operating data is unavailable.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **1.3** A periodicity for providing data. **1.4** The deadline by which the respondent is to provide the indicated data. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.	This requirement is replaced by proposed IRO-010-2, Requirement R2. **Proposed IRO-010-2, Requirement R2:** **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Criteria and processes for notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Provisions for periodic communications to support reliable operations.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1, Part 1.5:** **R1, Part 1.5:** Provisions for periodic communications to support reliable operations.
R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R3 through R6 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. **Proposed IRO-014-3, Requirement R4:** **R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R5:** **R5**. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R6:** **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014 as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism. The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent in proposed TOP-001-4, Requirement R1 which states that the Transmission Operator must act or issue Operating Instructions.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R1: **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-2, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-2, R2: **Proposed IRO-001-2, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-2, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance at the Transmission Operator level is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. Balancing Authorities provide assistance under approved EOP-001-2.1b, Requirement R1. **Approved EOP-001.2.1b, Requirement R1:** **R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities**.** **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting entity has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: **R7.1** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-010-2, Requirement R3: **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – reactive power: Replaced by approved VAR-001-4, Requirement R3 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-4, Requirements R1 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved VAR-001-4, Requirement R3: **R3**. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	The Transmission Operator and Balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2 and proposed IRO-008-2, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed iRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-4, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-006-4, Requirement R5, and proposed TOP-002-4, Requirement R4. **Approved INT-006-4, Requirement R5:** **R5**. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing

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	Authorities have been removed from the applicability of this requirement. SOLs and IROLs are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13. Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs. Second sentence – SOLs are set by the Transmission Operator in approved FAC-014-2, Requirement R2 according to the methodology distributed by the Reliability Coordinator in approved FAC-011-2, Requirement R4, Part 4.3. This should assure that SOLs are consistent for common facilities. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved FAC-014-2, Requirement R2:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: 4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	2.4 Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
14.2 Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5, Part 5.2:** **5.2** A mutually agreeable process for resolving data conflicts

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Generator Operators and Transmission Operators shall provide planned outage information. **1.1** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. **1.2** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. **1.3** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Parts 1.1, 1.2, and 1.3 are addressed as follows: **1.1** Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. **1.2** Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1. **1.3** Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators and Balancing Authorities through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. The data specification concept in proposed TOP-003-3 requires entities to provide data as requested. If there are outages of the equipment needed for providing that data, the entity experiencing the outage must notify the entity it is sending data to so that proper arrangements can be made for replacing the data or coming up with a plan to live without it. It is expected that the data specifications would incorporate such concepts. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, Requirement R2 and proposed IRO-017-1, Requirement R1, Part 1.4. **Proposed IRO-017-1, Requirement R1, Part 1.4**: **1.4** Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators **Proposed IRO-008-2, Requirement R2:** **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14 and proposed TOP-002-4, Requirement R2.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. **Approved FAC-014-2, Requirement R2:** **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the

<table>
<tr><th colspan="2">Standard TOP-004-2 — Transmission Operations</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>Operator may take such actions, as it deems necessary, to protect its area.</td><td>Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator.

Functional model v5:
14. Coordinates load shedding with, or as directed by, the Reliability Coordinator</td></tr>
<tr><td>R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

6.1 Monitoring and controlling voltage levels and real and reactive power flows.

6.2 Switching transmission elements.

6.3 Planned outages of transmission elements.

6.4 Responding to IROL and SOL violations.</td><td>The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired.

The second sentence was replaced as follows:

R6.1 is duplicative of approved VAR-001-4, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R10, R12 and R14.

R6.2 has been replaced by proposed TOP-001-3, Requirement R8.

R6.3 has been replaced by proposed IRO-017-1, Requirement R2.

R6.4 has been replaced by proposed TOP-001-3, Requirements R12 and R14.

Approved VAR-001-4, Requirement R1:
R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a
target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Proposed TOP-001-3, Requirement R8:
R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Proposed TOP-001-3, Requirement R10:
R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and</td></tr>
</table>

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, Part 3.3:** **3.3** A mutually agreeable security protocol **Proposed TOP-003-3, Requirement R5, Part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2** - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use. **1.3 -** Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.	The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11. **1.1** This Part is replaced by proposed TOP-003-3, Requirement R5. **1.2** This Part is replaced by proposed IRO-101-2, Requirement R3. **1.3** This Part is replaced by proposed IRO-010-2, Requirement R3. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R3, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.**1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, Part 1.2; proposed TOP-003-3, Requirement R1, Part 1.2; and proposed TOP-003-3, Requirement R2, Part 2.2.; and the proposed changes to the definitions of Operational Planning Analysis and Real-time Assessment.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-003-3, Requirement R2, Part 2.2: **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R3. **Proposed TOP-001-3, Requirement R10:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to:
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R3, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R3**: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R5 and R6. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4.** When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4**. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R6. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.
4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

<u>Facility Rating Exceedance</u>

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

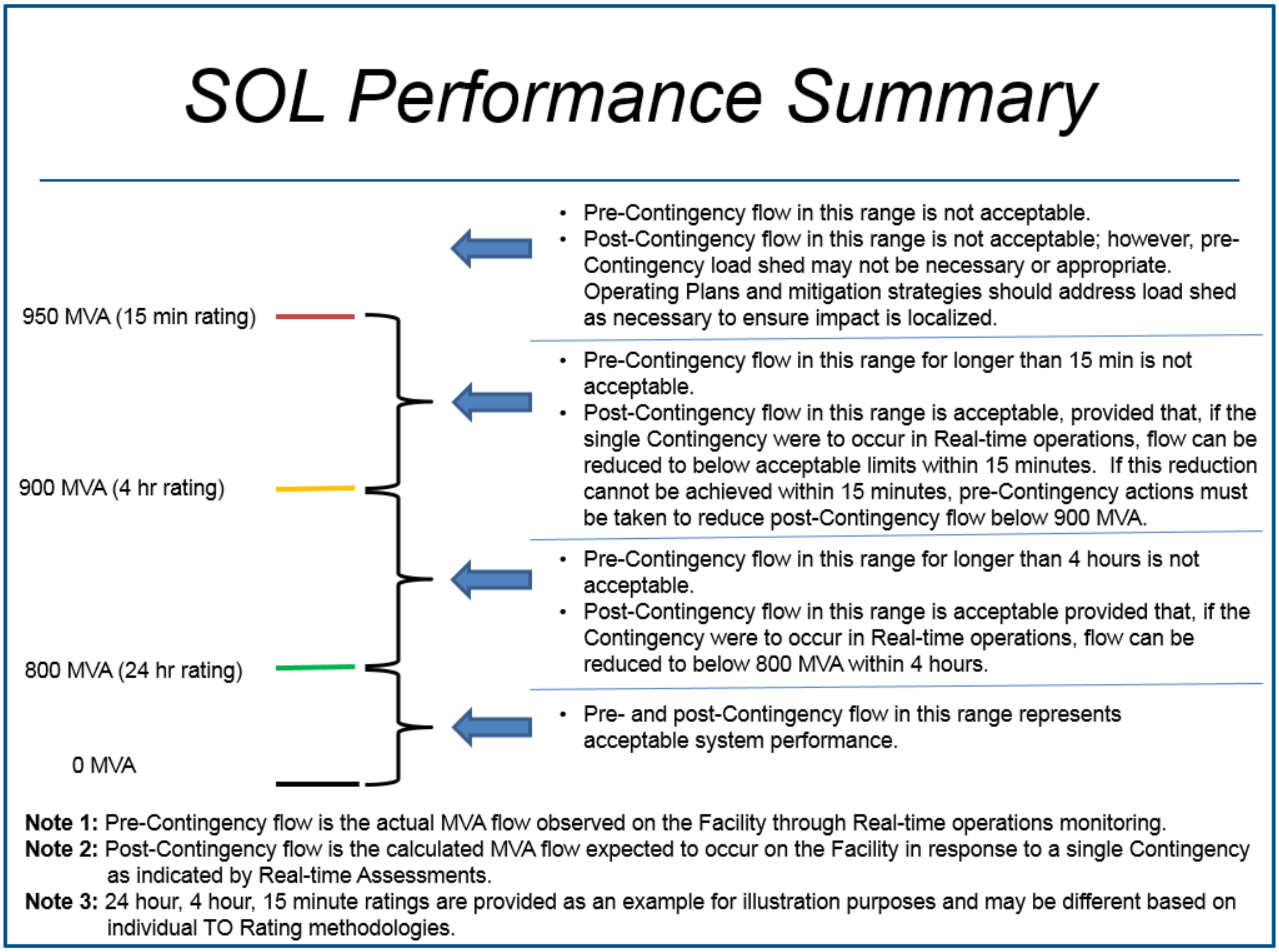

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time. Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid. Associated Operating Plans may include steps that can be taken to maintain acceptable pre- and post-Contingency system performance until additional studies can be performed to establish revised transient or voltage Stability limits.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

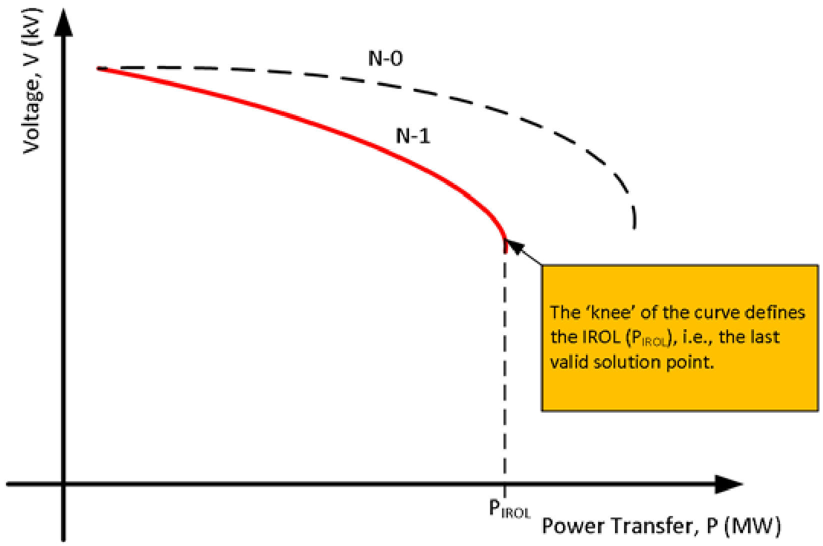

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in Operating Plan.	Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.
Emergency (4 hr)	All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in Operating Plan.	Use available effective actions and emergency procedures except Load shed consistent with timelines identified in Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in Operating Plan.	All of the above however, Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

3. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.

2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.

3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limit.

4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

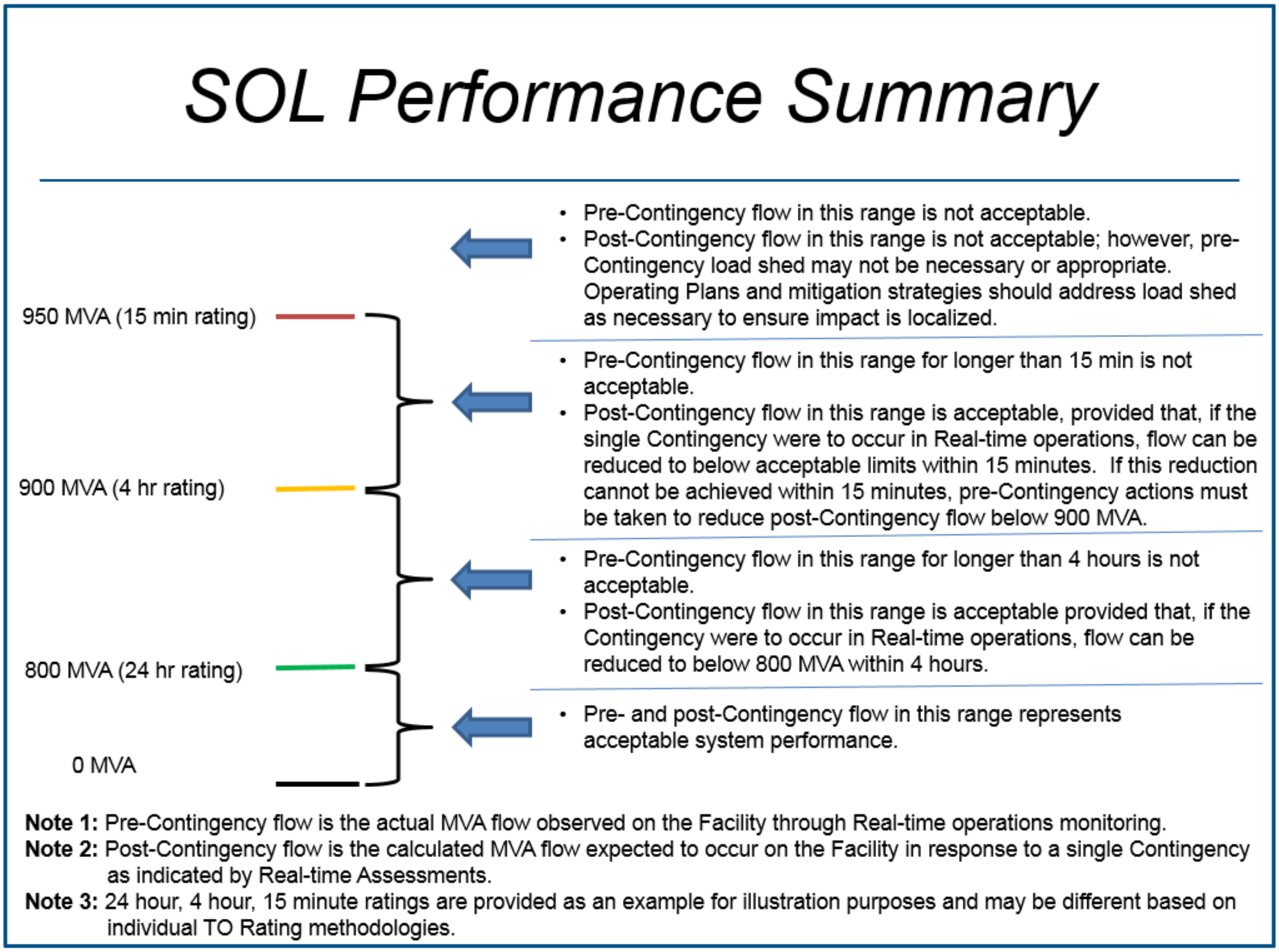

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time. Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid. Associated Operating Plans may include steps that can be taken to maintain acceptable pre- and post-Contingency system performance until additional studies can be performed to establish revised transient or voltage Stability limits.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

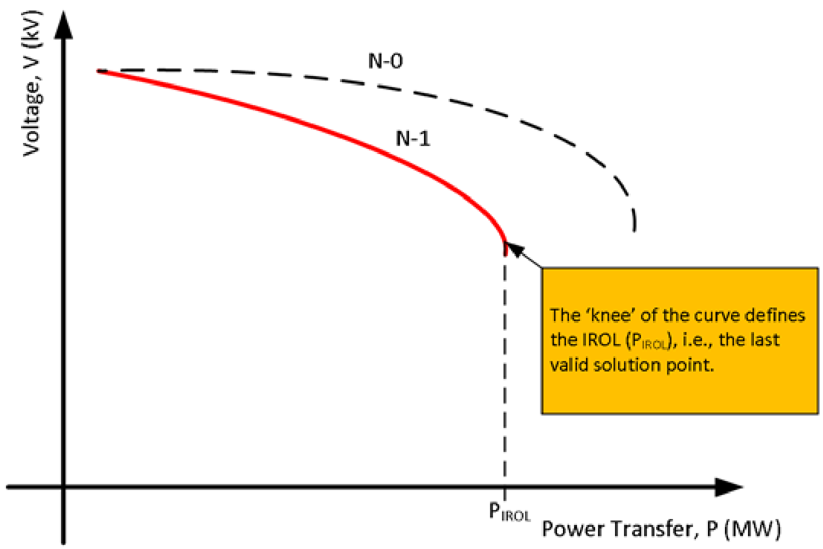

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
Normal (24 hr)	Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in Operating Plan.	Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.
Emergency (4 hr)	All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in Operating Plan.	Use available effective actions and emergency procedures except Load shed consistent with timelines identified in Operating Plan.
Emergency (15 min)	All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in Operating Plan.	All of the above however, Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

> Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operating Plan – A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process – A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating process.

Operating Procedure – A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a System Operator to take in removing a specific transmission line from service is an example of an Operating Procedure.

Time Horizons
When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

Plan and Operate within all System Operating Limits

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

SDT Consideration:

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability

Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

<u>SDT consideration:</u>

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load

conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

> <u>SDT consideration:</u>
>
> The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.
>
> > Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
> >
> > Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities
>
> As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.
>
> > **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
>
> The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.
>
> > Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

> Proposed TOP-001-3, Requirement R13: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

<u>SDT consideration:</u>

See previous response.

<u>Compliance with Reliability Directives</u>

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

<u>SDT consideration:</u>

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
>
> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES

> data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs. This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.
>
> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

<u>SDT consideration:</u>

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

<u>SDT consideration:</u>

The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.

Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

> Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

> How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?
>
> SDT consideration:
>
> The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

> <u>SDT consideration:</u>
>
> The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.
>
> In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.
>
>> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2:
>> The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
>> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
>> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal,

voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03

SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

<u>SDT consideration:</u>

<u>See response to paragraph 73 above.</u>

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers the situation where backup or redundant capabilities are required.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

<u>System Protection Coordination</u>

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for

protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

> Proposed IRO-014-2, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
> Identify applicable roles and reporting responsibilities.
> 1.1.1 Development and communication of outage schedules.
> 1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
> 1.2 Specify outage submission timing requirements.
> 1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
> 1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
>
> Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, Part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, non-BES data, and applicable relay data are included.

> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

> Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

<u>TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)</u>

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

<u>Plan and Operate within all System Operating Limits</u>

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

<u>SDT Consideration:</u>

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R3, R6, R7, and R8 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability

Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R4.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

<u>SDT consideration:</u>

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load

conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

> <u>SDT consideration:</u>
>
> The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.
>
> > Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
> >
> > Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities
>
> As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.
>
> > **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
>
> The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.
>
> > Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs. .

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

> Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

> Proposed TOP-001-3, Requirement R13: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

<u>SDT consideration:</u>

See previous response.

<u>Compliance with Reliability Directives</u>

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

<u>SDT consideration:</u>

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. ~~The p~~Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that ~~sub-100 kV~~ non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. ~~The Project 2014-03 SDT discussed this concern and concluded that an explicit requirement to use the data was an unnecessary administrative concern.~~ The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs. ~~These~~This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.
>
> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

~~See previous responses for this heading.~~ The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.

Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

SDT consideration:

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

<u>SDT consideration:</u>

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be

operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

<u>SDT consideration:</u>

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

<u>SDT consideration:</u>

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

<u>SDT consideration:</u>

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03

SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that "unknown states" cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

SDT consideration:

See response to paragraph 73 above.

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers ~~this~~the situation where backup or redundant capabilities are required.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

> Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-2, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

> Proposed IRO-014-2, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
> Identify applicable roles and reporting responsibilities.
> 1.1.1 Development and communication of outage schedules.
> 1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
> 1.2 Specify outage submission timing requirements.
> 1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
> 1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
>
> Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.
>
> Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: Mutually agreeable security protocol(s).

Proposed IRO-010-2, Requirement R3, Part 3.3: Mutually agreeable security protocol(s).

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, ~~sub-100 kV~~non-BES data, and applicable relay data are included.

> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

> Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to have a coordinated Operating Plan(s) which will have required the Reliability Coordinator to have reviewed the plans submitted by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	 The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, Part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, Part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here. The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, Parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	elements operated at less than 100 kV on BPS reliability.	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Proposed TOP-003-3, Requirement R1, Part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-Contingency operating conditions.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R14**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, Part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		(Real-time Assessment may be provided through internal systems or through third-party services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	Model parameters are outside the scope of this project.
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for non-BES data and monitoring as deemed necessary by the reliability entities. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		proposed TOP-001-3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed IRO-002-4, Requirement R4**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved FAC-001-2, Requirement R3:** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: 3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) 3.4 Level of detail of system models used to determine SOLs.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
21	GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.	Outside the scope of this project.
24	TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay settings. No relay settings should be set below a facility’s emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.	Outside the scope of this project.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and	(1) Phase angle calculation tools are outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	(2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day	(2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability. Training is outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	contingency analyses that address the angular differences across opened system elements.	

Mapping of Revised TOP and IRO Reliability Standards to Address 2011 Southwest Outage Report Recommendations

The following table provides a mapping of the recommendations applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority contained in the 2011 Southwest Outage Report. Several of the recommendations are specific to the particular facts and circumstances of the 2011 Southwest Outage and are therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
1	All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.	Next-day studies are required by proposed TOP-002-4, Requirement R1. Sharing the results of those studies is required in proposed TOP-002-4, Requirement R3. Providing results to the Reliability Coordinator is required in proposed TOP-002-4, Requirement R6. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R3:** Each Transmission Operator shall notify impacted NERC registered entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). **Proposed TOP-002-4, Requirement R6**: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
2	TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and	This is addressed in proposed TOP-002-4, through the revised definition of Operational Planning Analysis, and by the data specification standard

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	transmission outages and scheduled interchanges, which can significantly impact the operation of their systems.	which dictates that external system data must be part of the data specification. **Proposed TOP-002-4, Requirement R1**: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, part 1.1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities.	This item is addressed through proposed TOP-003-3. **Proposed TOP-003-3, Requirement R1:** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5**: Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
	Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.	Proposed IRO-008-2, Requirement R2 requires the Reliability Coordinator to have a coordinated Operating Plan(s) which will have required the Reliability Coordinator to have reviewed the plans submitted by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R2:** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
3	TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.	This is addressed in the data specification standards. **Proposed TOP-003-3, Requirement R1, part 1.1:** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1:** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
4	WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.	Interchange is now part of the list of things that a Reliability Coordinator must consider in the revised definition of Operational Planning Analysis. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
5	WECC RE should ensure better integration and coordination of the various subregions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between subregional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.	The proposed TOP-003-3 states that Transmission Operators must gather external network data and proposed TOP-002-4 mandates sharing the results of studies. **Proposed TOP-003-3, Requirements R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
6	TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.	The proposed TOP-003-3 explicitly states that Transmission Operators must obtain external network and sub-100 kV data. **Proposed TOP-003-3, Requirements R1, Part 1.1** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
7	TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.	The revised definition of Operational Planning Analysis states that "projected system conditions" must be considered which would include generator outages and high load periods. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
8	TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.	The proposed TOP-003-3 states that Protection System data must be obtained. And the revised definition of Operational Planning Analysis states explicitly that Protection Systems must be included in studies. Sharing of results is addressed in proposed TOP-002-4. **Proposed TOP-003-3, Requirements R1, Part 1.2**: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection

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		System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R3**: Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
9	WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a subregional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
	TOPs, TPs, and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of	The proposed TOP-003-3 addresses these items. **Proposed TOP-003-3, Requirements R1, Parts1.1 and 1.2:** 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

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	elements operated at less than 100 kV on BPS reliability.	1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. Planning Coordinators and Transmission Planners are outside the scope of this project.
10	WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.	This recommendation is not applicable to the Reliability Coordinator, Transmission Operator, and/or Balancing Authority and is therefore not addressed here.
11	TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Proposed TOP-003-3, Requirement R1, Part 1.1 states that Transmission Operators must include external network data in their respective data specifications. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. The revised definition of Real-time Assessment includes potential post-Contingency operating conditions.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
12	TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	The Project 2014-03 SDT has developed a requirement for the performance of a Real-time Assessment for Transmission Operators. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
13	TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency.	Proposed TOP-002-4, Requirement R2 states that Transmission Operators must have an Operating Plan to address SOL exceedances. Proposed TOP-001-3, Requirement R14 then states that the Transmission Operator must initiate its Operating Plan for mitigating and SOL exceedance. In addition, the SDT has developed a white paper on SOL Exceedance that clarifies the SDT position on SOL performance and SOL exceedance. **Proposed TOP-002-4, Requirement R2**: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R14**:

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	As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.	Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. The proposed TOP-003-3 explicitly requires the acquisition of Protection System data and the revised definitions of Operational Planning Analysis and Real-time Assessment call out Protection Systems as an item to be studied. **Proposed TOP-003-3, Requirement R1, Part 1.2:** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations.

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		(Real-time Assessment may be provided through internal systems or through third-party services.)
14	WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.	This recommendation is specific to the WECC Reliability Coordinator and is therefore not addressed here.
15	TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.	Proposed TOP-001-3, Requirement R9 states that Transmission Operators must notify impacted NERC registered entities of outages to monitoring and assessment capabilities. Training is outside the scope of this project. **Proposed TOP-001-3, Requirement R9**: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.
16	WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.	Model parameters are outside the scope of this project.
17	WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.	Designation of BES facilities is outside the scope of this project. However, the revised standards do incorporate the need for ~~sub-100 kV~~non-BES data and monitoring as deemed necessary by the reliability entities. If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in

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		proposed TOP-001-3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities'. If non-BES facilities do not impact the BES but are needed for completing models, then the SDT believes the situation is already covered in approved FAC-011-2, Requirement R3, Parts 3.1 and 3.4 which mandate that the Reliability Coordinator include external areas and the level of detail needed in models for determining SOLs within its established SOL methodology. **Proposed TOP-003-3, Requirement R1, Part 1.1**: A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed IRO-010-2, Requirement R1, Part 1.1**: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed IRO-002-4, Requirement R4**:

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved FAC-001-2, Requirement R3:** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: 3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) 3.4 Level of detail of system models used to determine SOLs.
19, 20, 22, 23, 25, 26	About coordination of SPS/RAS at the RC and TOP level.	Coordination of Special Protection Systems and Remedial Action Schemes is addressed in approved PRC-001-1.1a. Any changes to Protection System coordination issues is outside the scope of this project. Monitoring is addressed in proposed TOP-001-3, Requirement R10 and proposed IRO-002-4, Requirement R4. **Proposed TOP-001-3, Requirement R10**: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
		Proposed IRO-002-4, Requirement R4: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
21	GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.	Outside the scope of this project.
24	TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay settings. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.	Outside the scope of this project.
27	TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and	(1) Phase angle calculation tools are outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	(2) mitigation and operating plans for reclosing lines with large phase angle differences.	(2) Consideration of phase angle limitations has been added to the proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA). **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) While there is no explicit requirement for seasonal studies, the Reliability Coordinator has the authority to request such a study if it believes it is needed for reliability.
	TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day	Training is outside the scope of this project.

#	Recommendation	Mapping to Proposed TOP/IRO Reliability Standards
	contingency analyses that address the angular differences across opened system elements.	

Project 2014-03 - Revision of TOP/IRO Reliability Standards

Resolution of Issues and Directives

The following table contains a list of all FERC directives, industry issues, and Independent Expert Review Panel (IERP) recommendations associated with the standards being revised in Project 2014-03, with proposed resolutions.

Standard	Source	Language	Resolution
IRO-001-3	FERC Order 693	892. Consider commenters' suggestions as part of the standards development process. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.	The SDT has added measures for all requirements. The Regional Reliability Organization has been removed from the standards.
IRO-001-3	FERC Order 693	893. Consider commenters' suggestions as part of the standards development process. FirstEnergy	The SDT has considered the commenter's suggestions and believes that safety refers to any

Standard	Source	Language	Resolution
		suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.	type of safety including personal or equipment and that no additional wording is necessary. If a generator receives conflicting Operating Instructions, the generator should contact the Reliability Coordinator for clarification. The NERC Functional model refers to the Reliability Coordinator as overall authority.
IRO-001-3	FERC Order 693	895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.	The SDT has considered the comments and believes that a Reliability Coordinator can direct a Qualifying Facility (registered as a GO or GOP) to act through the issuance of Operating Instructions. Therefore, no additional requirements are necessary.
IRO-001-3	FERC Order 693	896. Eliminate the references to the regional reliability organization as an applicable entity. Paragraph 896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1 to substitute "Regional Entity" for "regional reliability organization" and reflect	The SDT has removed all references to the Regional Reliability Organization from the standards.

Standard	Source	Language	Resolution
		NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	
IRO-001-3	FERC Order 693	897. Consider adding measures and levels of non-compliance. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	The SDT has added measures and Violation Severity levels (VSLs) (which replaced levels of non-compliance) for each requirement.
IRO-001-3	FERC's December 20, 2007 and April 4, 2008 Orders	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance	The SDT has established requirements that apply to the Load-Serving Entity. **Proposed TOP-001-3, Requirement R3**: **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be

Standard	Source	Language	Resolution
		filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been	physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard	Source	Language	Resolution
		incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability First (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf)	

Standard	Source	Language	Resolution
		· NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.	
IRO-001-3	Fill in the Blank Team	Remove ", sub-region, or interregional coordinating group" from R1	Terms have been removed from the standard.
IRO-001-3	Version 0 Team	Inability to perform needs to be communicated	Clarity has been provided to address this issue throughout the various standards.
IRO-001	Version 0 Team	What is meant by 'interest of other entity'?	The SDT proposes to retire Requirement R9. All Reliability Coordinator Standard Requirements are developed so that the Reliability Coordinator shall act in the interest of reliability for the Reliability Coordinator Area and the Interconnection.
IRO-001-3	Fill in the Blank Team	Consider removing "Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market	The purpose statement has been revised accordingly.

Standard	Source	Language	Resolution
		participant over another." from the Purpose section of the standard.	Purpose: To establish the responsibility of Reliability Coordinators to act or direct other entities to act to prevent an Emergency.
IRO-001-3	NERC Audit Observation Team	All applicable registered functions shall comply with RC directives unless such actions would violate safety, equipment or regulatory or statutory requirements. Inform the RC immediately of the inability to perform such directives. For audit purposes, what is acceptable evidence?	Measure M2 contains the provisions for suitable evidence. **Proposed IRO-001-4, Measure M2**: **M2**. Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall have and provide evidence which may include, but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it complied with its Reliability Coordinator's Operating Instruction, unless the instruction could not be physically implemented, or such actions would have violated safety, equipment, regulatory or statutory requirements. In such cases, the Transmission Operator, Balancing Authority, Generator Operator, or Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Reliability Coordinator's Operating Instruction. If no event has occurred, the Transmission Operator, Balancing Authority, Generator Operator, or

Standard	Source	Language	Resolution
			Distribution Provider may provide an attestation that an event has not occurred.
IRO-001-3	VRFs Team	R6 - Since the RC must be NERC certified, it stands to reason that anyone performing RC tasks should be certified. However, since the RC still retains the accountability for actions, and requirement 4 handles the agreements, this requirement is a medium risk.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
IRO-001-3	IERP	Requirement R1 content is incomplete. IERP recommended addressing 3 concepts as follows: RC has the authority to direct others to act. RC has the obligation to direct others to act to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.	The NERC Functional Model v5 spells out the authority of the Reliability Coordinator on page 30 under the description of the Reliability Coordinator functional entity. Proposed IRO-001-4, Requirement addresses the obligation of the Reliability Coordinator to direct others to act. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. The term 'Reliability Directive' has been replaced with the defined term 'Operating Instruction.' Proposed COM-002-4 determines the protocol for issuing Operating Instructions.

Standard	Source	Language	Resolution
		When directing others to act in accordance with this requirement, a RC must identify its directive as a "Reliability Directive". Consider consolidating with other authority-related standards and COM-003 in a single Authority standard as follows: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.	The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-001-3	IERP	IERP viewed Requirement R2 language as unclear and unable to be practically implemented. Questioned whether equipment requirements were a valid reason for not complying with RC direction. IERP proposed covering this requirement under a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.

Standard	Source	Language	Resolution
		safety, equipment, regulatory, or statutory requirements.	
IRO-001-3	IERP	IERP viewed content of Requirement R3 as incomplete by not requiring a reason for not complying with the RC's direction IERP recommended consolidating into a single Authority standard (see requirement above, which would replace both IRO-001 requirements R2 and R3)	The SDT does not agree with the IERP statement/suggestion. The SDT feels this is more of a compliance issue and should not be addressed in Real-time.
IRO-002-1	FERC Order 693	905 - Require a minimum set of tools that must be made available to the reliability coordinator. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.	This directive is beyond the scope of this project and will be resolved in a future project.
IRO-002	Version 0 Team	R5 – define synchronized information system	The term is not used in the revised standards.
IRO-002	Version 0 Team	R7 – define 'adequate' tools and 'wide-area'	The terms are not used in the revised standards
IRO-002-1	Version 0 Team	Words such as 'easily understood' and 'particular emphasis' need to be tightened	The terms are not used in the revised standards
IRO-002-3	IERP	IERP viewed Requirement R1 as incomplete. RC also needs to approve any other work being done on the tools, hardware/software/telecom systems within the RC that could affect the quality and the content of the data coming into the control center.	Proposed IRO-002-4, Requirement R2 addresses this issue. **Proposed IRO-002-4, Requirement R2**: **R2**. Each Reliability Coordinator shall provide its System Operators with the authority to approve

Standard	Source	Language	Resolution
		Also consider consolidating with Project 2009-02 Requirement R1 was proposed for consolidation under a new Authority standard: Authority R2 Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.	planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
IRO-002-3	IERP	IERP viewed Requirement R2 as incomplete. Procedures need to address not only tools outages, but also tools maintenance or other inhibitors to quality performance of analysis tools. Also consider consolidating with Project 2009-02	The SDT added 'maintenance' approval to proposed IRO-002-3, Requirement R3. This includes all work being done on monitoring and analysis capabilities and not just those that will cause an outage. **Proposed IRO-002-4, Requirement R2**: **R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities.

Standard	Source	Language	Resolution
			The Project 2014-03 SDT is addressing directives assigned to Project 2009-02 as well as issues identified in the NOPR on the TOP/IRO standards.
IRO-003	Order 693	914. … we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area …	The term is not used in the revised standards. The proposed data specification concept allows for the Reliability Coordinator to ask for any reliability related data that it needs in order to fulfill its reliability tasks thus obviating the need for a specific criteria for determining critical facilities. And specific requirements for monitoring have been added for the Reliability Coordinator. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
IRO-004-1	Order 693	934. In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each	Measures have been added to all requirements.

Standard	Source	Language	Resolution
		Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	
IRO-004-1	Order 693	935. …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency	The SDT has addressed this issue in proposed IRO-008-2 and TOP-002-4 as well as through the revised definitions of Operational Planning Analysis and Real-time Assessment. SOLs must be controlled according to the Operating Plan which is set up on time-based facility ratings (see SOL Exceedance White Paper for further details). IROLs are controlled to the IROL T_v which by definition is always less than 30 minutes. Approved IRO-009-1, Requirement R1 also addresses this item. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard	Source	Language	Resolution
			Proposed TOP-002-4, Requirement R1: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed IRO-009-1, Requirement R1**: **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
IRO-005	FERC Order 693	520. Further, we clarify that we did not propose to require an entity to inform its reliability coordinator of every action it takes. Instead, the proposed directive included a Requirement for the reliability coordinator to assess and approve only those actions that have	The SDT addresses the need for Reliability Coordinator assessment and approval on a requirement by requirement basis. For example, see proposed IRO-008-2, Requirements R3 and R6.

Standard	Source	Language	Resolution
		impacts beyond the area views of transmission operators and balancing authorities. We remain convinced that it is the reliability coordinator's responsibility to ensure Reliable Operation of its reliability coordinator area. The reliability coordinator must also ensure that actions taken by operating entities under its authority will not have wide-area impacts that would adversely impact Reliable Operation of the Bulk-Power System. Therefore, we adopt the proposed directive as stated in the NOPR. 525. Accordingly, we direct the ERO to include a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities, including how to determine whether an action needs to be assessed by the reliability coordinator. This Requirement is best developed under the Reliability Standards development process including the consideration whether this Requirement should be included in this communications Reliability Standard or an operating Reliability Standard.	**Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R5**: **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.
IRO-005-1	FERC Order 693	946. "Conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROLS, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to NERC.	Completed and filed in Oct 2008
IRO-005-1	FERC Order 693	950- Provide further clarification that reliability coordinators and transmission operators direct control	The SDT has proposed IRO-001-4, Requirement R1 to address the Commission's suggestion for

Standard	Source	Language	Resolution
		actions, not LSEs as part of the standard development process. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.	clarification. Proposed TOP-001-4, Requirement R1 also addresses this issue. **Proposed IRO-001-4, Requirement R1**: **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed TOP-001-4, Requirement R1:** **R1.** Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions.
IRO-005-1	FERC Order 693	951-"Measures and levels of non-compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency, and causes of the violations and whether these occur during normal or contingency conditions. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO-005-1through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration,	The SDT has added measures and VSLs (which replaced levels of non-compliance) for each requirement.

Standard	Source	Language	Resolution
		frequency and causes of the violations and whether these occur during normal or contingency conditions.	
IRO-005-1	Fill in the Blank Team	R14 has regional reference	The term is not used in the revised standards.
IRO-005-1	Version 0 Team	R10, 11 & 12 – RA not empowered to do this	RA is no longer an applicable entity in the revised standards.
IRO-005-4	IERP	Requirement R1 is incomplete--needs to include Emergency. Requirement R1 reads: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. Also - there are gaps between the old std IRO-005-3 R2 to IRO-005-4: missing is: There is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1 Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard	The SDT replaced Adverse Reliability Impact with Emergency in all requirements. Emergency is a broader term. Proposed IRO-002-4, Requirement R3 addresses the issue of monitoring. **Proposed IRO-002-4, Requirement R3**:

Standard	Source	Language	Resolution
		and Disturbance Control Standard requirements. (Minus strikethrough) FROM IRO-005-3 R9: Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. The SDT believes all appropriate items, including Special Protection System evaluation and awareness is addressed through the revised definitions of Real-time Assessment and Operations Planning Analysis. The data specification has been revised to explicitly address Special Protection Systems. **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1. Part 1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
		From IRO-005-3 R10: In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	The SDT has addressed the issue of resolving differences in limits in proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R18**: **R18.** Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.

Standard	Source	Language	Resolution
		Recommend consolidating with IRO-008 R3.	The SDT has consolidated requirements and standards as it believes appropriate.
IRO-005-4	IERP	The proposed standard creates a gap in outage coordination by proposing to retire IRO-005-3 R6. This could be resolved through an Authority standard as proposed by the IERP From IRO-005-3 R6: The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The SDT has proposed a new standard, IRO-017-1 Outage Coordination, to address this issue.
IRO-005-4	IERP	Requirement R2 should also include Emergency Requirement R2 reads: Each Reliability Coordinator that identifies an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area when the problem has been mitigated. Note: there is a possible gap for RC in IRO-005-4 regarding RC handling emergencies as this has been dropped from IRO-005-3.1	The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency.

Standard	Source	Language	Resolution
		Recommend moving to IRO-008 and create an R4	
IRO-014-2	IERP	Gap in Requirement R1 - Need to identify RC's authority to direct another RC to take action - suggestion: create another Requirement, i.e., R6 (in proposed authority standard). Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT does not agree with this recommendation. A Reliability Coordinator does not direct another Reliability Coordinator. Proposed IRO-014-3 describes how to coordinate between Reliability Coordinators.
IRO-014-2	IERP	R2 is administrative and should be deleted	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R3 implements plan from R1; it should be combined with R1	The SDT believes that combining the requirements would create a complex requirement with multiple objectives that would be difficult to measure for compliance.
IRO-014-2	IERP	Requirement R4 is administrative and should be deleted.	The SDT believes that this is not strictly an administrative requirement and serves a reliability purpose.
IRO-014-2	IERP	R5 should require notification of “all IMPACTED RCs"; not "ALL"	The SDT has added ‘impacted’ to appropriate locations in the standards.
IRO-014-2	IERP	R6 should be consolidated with other standards that incorporate the concept of operating to the most conservative for reliability - IRO-009-1 R5	Approved IRO-009-1 only addresses IROLs. Proposed IRO-014-3 addresses all limits.

Standard	Source	Language	Resolution
		R6 reads: During each instance where Reliability Coordinators disagree on the existence of an Adverse Reliability Impact each impacted Reliability Coordinator shall operate as though the problem exists.	
IRO-014-2	IERP	Requirement R7 should be retired. The reliability objective is covered under R6, and also supported by IRO-009-1 R5	The SDT believes that the two requirements are sufficiently distinct to warrant separateness. Requirement R6 speaks to actual operations. Requirement R7 speaks to having an established plan. The SDT believes that reliability is best served by having a plan to follow.
IRO-014-2	IERP	Requirement R8 should be retired. The reliability objective is covered under R6.	The SDT does not agree with this recommendation. Requirement R8 is a separate requirement.
IRO-016	VRF's Team	R1.2.1 & R2 – ambiguous	Requirement R2 was approved for retirement by FERC effective January 2014. Requirement R1, part 1.2.1 was incorporated in the set of requirements in proposed IRO-014-3, and ambiguous language has been deleted.
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of “emergency” and define the criteria for entering into the various states. Also define the authority for declaring these states.	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in

Standard	Source	Language	Resolution
			the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This concern is addressed in proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	The term is not used in the revised standards
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been revised to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The SDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there, the SDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is

Standard	Source	Language	Resolution
			listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-001-2	IERP	Requirement R1 phrase "unless it violates requirements" is too permissive or there may be a better way to phrase it Consider consolidating TOP-001-2 Requirements R1 and R2 and all other standards requirements related Authority to into a single Authority standard as follows: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under [Authority standard R1] unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.	The SDT believes that this is well understood language. The SDT believes that a separate authority standard is not necessary. Existing standards and requirements in conjunction with the Functional Model v5 are sufficient to address the authority issue raised here.
TOP-001-2	IERP	The language “emergency assistance” in Requirement R4 is unclear. When and how must assistance be rendered, and what type? BA’s should be included as functional entity. Consider moving R4 to EOP standards (this is an "emergency" operating requirement)	The SDT revised the language for clarity and included the Balancing Authority. **Proposed TOP-001-3, Requirement R7:** **R7**. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures,

Standard	Source	Language	Resolution
			unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
TOP-001-2	IERP	Requirement R5 should also include notification of Emergencies (in addition to ARI), and should include Bas. R5 states: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load.	The SDT added impacted Balancing Authorities. The SDT replaced Adverse Reliability Impact with Emergency in all requirements for consistency. The definition of Adverse Reliability Impact is encompassed in Emergency. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
TOP-001-2	IERP	R6 needs to include real time outages of telecom as well as planned outages.	The SDT added telecommunications to the requirement. **Proposed TOP-001-2, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of outages of telemetering and telecommunication equipment, control equipment, monitoring and assessment capabilities, and associated communication channels between it and the affected entities. COM standards are not in scope for this project.

Standard	Source	Language	Resolution
		Requirement should be covered under COM-001	
TOP-001-2	IERP	Requirement R8 does not cover all information needed for reliability. It should cover 1) SOLs within a TOP's/RC's footprint, 2) SOLs that are within one TOP's/RC's footprint that could affect another entity and 3) an SOL that spans into 2 TOP's/RC's footprints The requirement should also obligate the TOP to also inform impacted TOPs (The entity that could be impacted must tell the TOP that could impact them that it needs the info)	The SDT has addressed issue 1 in proposed TOP-001-3, Requirement R15. SOLs that cross boundaries are taken care of at the Reliability Coordinator level. **Proposed TOP-001-3, Requirement R15:** **R15**. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.
TOP-002-3	Order 693	1597. Consider ISO-NE recommendation that the reference to "transmission service provider" in TOP-002-2 R12 be replaced by TOP and/or TO. Requirement R12 states: The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.	This requirement is now addressed by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **R6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or

Standard	Source	Language	Resolution
			A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3**: **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. Approved MOD-030-2, Requirement R2.4: Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
TOP-002-3	Order 693	1598. Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including non-BES data as necessary. Next-day analysis is performed using Operational Planning Analysis. Approved NUC-001-2.1 also applies here. **Proposed IRO-010-2, Requirement R1 and Part 1.1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-

Standard	Source	Language	Resolution
			time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **Proposed Definition: Operational Planning Analysis** - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs

Standard	Source	Language	Resolution
			including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
TOP-002-3	Order 693	1600. Address critical energy infrastructure confidentiality as part of the routine standard development process	The data specification standards now contain provisions for addressing security of data. **Proposed IRO-010-2, Requirement R3, Part 3.3**: **R3. Part 3.3** A mutually agreeable security protocol. **Proposed TOP-003-3, Requirement R5, Part 5.3:** **R5. Part 5.3** A mutually agreeable security protocol.
TOP-002-3	Order 693	1601. …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages	SOLs are the responsibility of the Transmission Operator and IROLs are the responsibility of the Reliability Coordinator. This issue is addressed in proposed changes to the IRO standards. Approved IRO-009-1, Requirement R1 also applies. **Proposed IRO-008-2, Requirement R1**: **R1**. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Standard	Source	Language	Resolution
			Proposed IRO-008-2, Requirement R2: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3**: **R3**. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.
TOP-002-3	Order 693	1606. Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm	The SDT agrees and has addressed the issue in proposed TOP-002-3, Requirement R4, part 4.4:

Standard	Source	Language	Resolution
		load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.
TOP-002-3	Order 693	1608. Require simulation contingencies to match what will actually happen in the field	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment accordingly. The definitions require Contingencies to match field conditions as they require evaluations against projected system conditions for Operational Planning Analysis and system conditions for Real-time Assessment. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The

Standard	Source	Language	Resolution
			assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
TOP-002-3	IERP	Requirement R1. TOP-008-1 R4 needs to be incorporated into TOP-002-3 requirement R1. Also - the definition of "Operational Planning Analysis" provides too much latitude in time. Recommend removing the parenthesis in the definition; the entity will make the determination and document (documentation is evidence) the applicability of what it uses for their next day study	The SDT revised the definition of Operating Planning Analysis and Requirement R1. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next

Standard	Source	Language	Resolution
			day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
TOP-003-0	FERC Order 693	1620. …direct the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these type of issues, specifically proposed IRO-017-1, Requirement R1. This new standard takes into account the recommendations from the Independent Expert Review Panel and SW Outage Report and brings all of the various outage coordination issues into one cohesive standard. **Proposed IRO-017-1, Requirement R1:** **R1**. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of Project 2007-03 in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional

Standard	Source	Language	Resolution
			standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. In response to concerns raised by the IERP and the SW Outage Report, the SDT has developed proposed IRO-017-1 Outage Coordination. This standard requires the development of a coordinated outage process between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner. If so desired, a Reliability Coordinator could include lead times in its process. (See proposed IRO-017-1, Requirement R1, Part 1.2.) In addition, proposed IRO-010-2 and TOP-003-2 dealing with data specifications could also cover this issue. The data specification must include any and all data required by the Reliability Coordinator, Transmission Operator and Balancing Authority. Planned outage data and timings could be included in such a data specification.

Standard	Source	Language	Resolution
			Therefore, the SDT has not included a standard lead time in the revised requirements. **Proposed IRO-017-1, Requirement R1, Part 1.2:** **1.2** Specify outage submission timing requirements.
TOP-003-0	Order 693	1622. Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	The SDT has developed proposed IRO-017-1 Outage Coordination to address these types of issues. **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area.
TOP-003-0	Order 693	1624. Direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	The data specification standard require that a Reliability Coordinator and Transmission Operator acquire all of the data necessary for them to fulfill their reliability functions including sub-100 kV data as necessary. **Proposed IRO-010-2, Requirement R1 and Part 1.1**: **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1 A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time

Standard	Source	Language	Resolution
			monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **Proposed TOP-003-3, Requirement R1 and Part 1.1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
TOP-003-2	IERP	Requirements R1 and R2 do not address level of accuracy required; see if this is provided elsewhere (i.e. project 2009-02) Consolidate R1 and R2 at minimum; at max consolidate with RC (IRO-010-1a R1)	Level of accuracy is one of the issues identified in the Real-Time Tools Best Practices Task Force Report. NERC is currently instituting a review of all of the recommendations in various reports, including the Real-time Tools Best Practices Task Force report, to see what actions should be taken, if any are still required, to address recommendations in the reports. The SDT does not want to consolidate the two responsibilities. The industry has clearly indicated a desire for separate standards for the Reliability

Standard	Source	Language	Resolution
			Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Consolidate R3 and R4 at minimum; at max consolidate with RC (IRO-010-1a R2)	The SDT does not want to consolidate the two requirements or the two standards. The SDT feels Requirements R3 and R4 are for different tasks. The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-003-2	IERP	Requirement R5 should be consolidated with IRO-010-1a R3	The industry has clearly indicated a desire for separate standards for the Reliability Coordinator and Transmission Operator where possible.
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	The SDT believes that this issue has been addressed through the more stringent definitions proposed for Operational Planning Analysis, Real-time Assessment, and the requirement for the Transmission Operator to perform an Operational Planning Analysis as well as a Real-time Assessment every 30 minutes and to create an Operating Plan for mitigation of SOL exceedances. The SDT has developed a white paper on the topic of SOL exceedance to explain the technical rationale behind this resolution. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known

Standard	Source	Language	Resolution
			Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4, Requirement R1**: **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2**: **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances

Standard	Source	Language	Resolution
			identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14**: **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
TOP-004-1	Order 693	1637. …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Completed and filed in Oct 2008.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (… the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an	The SDT feels that approved EOP-001-2.1b dealing with emergency operations planning covers the intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, approved FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under … high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	Order 693	1639. Consider Santa Clara's comment in the SDT process. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows	The data specification standards require that entities obtain all of the data that they need to perform their reliability functions. This would include frequency, voltages, real and reactive power flows, and any other data that the entity needs. Proposed TOP-001-3, Requirements R10 and R11 also address this item. **Proposed IRO-010-2, Requirement R1**: **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R1**: **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-001-3, Requirement R10**:

Standard	Source	Language	Resolution
			R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11**. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	The SDT has clarified the issue. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL $T_{v.}$
TOP-005	Order 693	1648. ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status	The SDT has added specific parts to the data specification standards as well as revising the

Standard	Source	Language	Resolution
		of special protection systems and power system stabilizers in Attachment 1.	definitions of Operational Planning Analysis and Real-time Assessment to address this issue. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**:

Standard	Source	Language	Resolution
			1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-005	Order 693	1650. Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process. FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. ISO-NE recommends that the reference to "purchasing-selling entity" should be replaced with LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-3. Requirement R4 has been superseded by proposed TOP-003-3 which does include the indicated entities and has deleted PSE. **Proposed TOP-003-3, Requirement R5**: **R5.**Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using:
TOP-005	Order 693	1651. … deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.	The SDT believes that confidentiality is a market issue and not a reliability issue and as such it does not belong in the Reliability Standards. However, security of information is a reliability concern and the SDT has addressed that issue through the addition of requirements for establishing security protocols in data exchanges.

Standard	Source	Language	Resolution
			Proposed TOP-003-3, Requirement R5, Part 5.3: 5.3 A mutually agreeable security protocol. **Proposed IRO-010-2, Requirement R3, Part 3.3**: 3.3 A mutually agreeable security protocol.
TOP-005	Order 693	1660. Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system	This directive is beyond the scope of this project and will be resolved in a future project.
TOP-006	Order 693	1665. Clarify the meaning of appropriate technical information concerning protective relays	That term is no longer used in the standards. To address concerns about the status of protection systems, the SDT has incorporated explicit references in the definitions of Operational Planning Analysis and Real-time Assessment and the data specification standards. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Standard	Source	Language	Resolution
			Proposed Definition: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2**: 1.2 Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
TOP-006	Order 693	1664/1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	All requirements now have measures.
TOP-006	Order 693	1673. Direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan.	Analysis is required in proposed TOP-002-3, Requirement R1 and in proposed TOP-001-3, Requirement R13. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1 and proposed

Standard	Source	Language	Resolution
		NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.	TOP-001-3, Requirement R13 as shown in the revised definition of Operational Planning Analysis and Real-time Assessment. Additionally, approved NUC-001-2.1, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-3. Approved NUC-001-2, Requirements R3 & R8 cover the information flowing back to the nuclear plant operator. **Proposed Definition: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential

Standard	Source	Language	Resolution
			(post-Contingency) operating conditions. The assessment may reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-3, Requirement R1**: **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13**: **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved NUC-001-2.1, Requirement R3**: **R3**. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. **Approved NUC-001-2.1, Requirement R4.1**:

Standard	Source	Language	Resolution
			4.1 Incorporate the NPIRs into their operating analyses of the electric system. **Approved NUC-001-2.1, Requirement R8:** **R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.
VAR-001-1	Order 693 Transferred from Project 2013-04 Voltage and Reactive Control	1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in	The SDT has clarified the issue of having the Reliability Coordinator provide oversight. The proposed requirement uses the term 'Facilities' which is defined as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." Therefore, the requirement covers voltage and reactive resources. **Proposed IRO-002-4, Requirement R3**: **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any

Standard	Source	Language	Resolution
		VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
INT-006-1	Order 693 Transferred from Project 2008-12 Coordinate Interchange Standards	866. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that makes it applicable to reliability coordinators and transmission operators. The Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	An equally efficient and effective method of addressing the directive was approved by the Board and filed with FERC by Project 2008-12 SDT by including the term 'Interchange' in the definition of Operational Planning Analysis. This change has been retained by Project 2014-03. Proposed IRO-008-2, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. Then, in proposed IRO-008-2, Requirement R2, the Reliability Coordinator must develop a plan for addressing the problem. Similar requirements exist for the Transmission Operator in proposed TOP-002-3. **Proposed: Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation may reflect applicable inputs including,

Standard	Source	Language	Resolution
			but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **Proposed IRO-008-2, Requirement R2**: **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed IRO-008-2, Requirement R3:**

Standard	Source	Language	Resolution
			R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R3:** **R3**. Each Transmission Operator shall notify impacted entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).

NERC Operating Committee Response to NERC Standards Committee / RISC Triage of IERP Gaps

April 2, 2014

The NERC Operating Committee reviewed three perceived gaps, Outage Coordination, Governor Frequency Response, and Situational Awareness, as identified by the Independent Experts in their June 2013 report. As an important step in this review, the OC's Executive Committee met via WebEx with the Independent Experts to more thoroughly discuss and understand the thinking which led to these elements being cited as possible gaps. During the WebEx, the OCEC and the Independent Experts also reviewed all of the proposed requirements in the Independent Experts draft Authority matrix. The results of the OC's discussions, and the Project 2014-03 SDT's consideration within the revised TOP and IRO standards for two of the three perceived gaps (Outage Coordination and Situational Awareness) are presented below. The third gap identified by the Independent Experts, Governor Frequency Response, is outside the scope of Project 2014-03.

Outage Coordination

Draft requirements 3, 7, 8 and 9 of the Independent Experts draft Authority Standard focus on Outage Coordination. One concern recognized the fact that the Reliability Coordinators have a wide area view and broader situational awareness, allowing for early identification and resolution of conflicts. Therefore the RCs should have the most influence on outage coordination. Further concerns identify standards that are currently in flux, particularly those remanded standards in which requirements are being removed.

Operating Committee opinion

The Operating Committee concurs that Outage Coordination is an important grid reliability function. Outage coordination should originate from the TOPs and GOPs; with conflicts resolved by their respective RC. It makes sense for this process to begin with a set of previously approved scheduled long term outages with a sufficient time margin for results to be incorporated into seasonal operating studies. Further, the RC should retain the authority for final approval up to the time the asset is removed from service, as well as recall authority (if technically feasible and appropriate to recall) as needed to prevent or mitigate emergencies.

Longer term outage coordination is necessary for those assets that require long maintenance planning pursuant to the type of work required, such as turbine rebuilds, nuclear refueling, etc. This likely belongs in the scope of the Planning Coordinator (PC) for outages planned more than 12-months into the future. A Reliability Standard could be written that requires PCs to coordinate long term outages and which requires responsible entities (e.g., GOs, TOs) to request a time slot in which to perform whatever maintenance is required.

In either case, during the longer term planning horizon, or the Operations planning and real time operations time frame, each PC or RC should have an understanding of the impacts on neighboring PCs or RCs when those assets are planned to be out or are forced out, with notification/coordination requirements with these PCs or RCs.

SDT response:

To enhance reliability, the Project 2014-03 SDT has provided explicit requirement language to address the need for planned outage coordination at the Reliability Coordinator level. See proposed IRO-014-3, Requirement R1, part 1.4. The Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address overall outage coordination issues.

Proposed IRO-014-3, Requirement R1, part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Situational Awareness (EMS RTCA models)

In this gap the Independent Experts recommend the development of a standard that defines the requirements for EMS RTCA models or performance expectations of the models (Project 2009-02 – Real Time Monitoring and Analyses Capabilities).

Operating Committee opinion

The Operating Committee has a concern that this gap could be interpreted as recommending a "HOW" standard where specific tools would be required even for the smallest TOPs, as opposed to a "WHAT" standard that would allow for other ways to accomplish the objective. In conversations with the Independent Experts it became clear that proper situational awareness was the primary concern. The OC concurs that real time contingency analysis process (real time updated topology and telemetry) should be performed on each BES facility. This functionality could be performed by use of an RTCA application at the TO or RC level, or coverage by alternate means would be appropriate.

SDT response:

The Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13. In addition, the Project 2014-03 SDT has revised the definition of Real-time Assessment to allow for contracting needed services to accommodate concerns for smaller entities.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase

angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Remainder of the draft Authority Standard Requirements

Authority R1

Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.

Operating Committee opinion

The current IRO-001-1.1 and TOP-001-1a are expected to be retired and replaced by IRO-001-3. In either case, these standards contain the authority to act, but the requirement to act appears to be implicit. The OC agrees that the RC, TOP and BA should explicitly be required to act.

SDT response:

The Project 2014-03 SDT agrees and has adjusted the wording in the standards to address this issue.

Proposed IRO-001-4, Requirement R1: Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R1: Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

Proposed TOP-001-3, Requirement R2: Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

Authority R2

Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.

Operating Committee opinion

The current IRO-002-2 provides for the RC to have control of its tools but does not include the TOP or BA. IRO-002-2 is expected to be retired and replaced by IRO-002-3, which clarifies that the system operators have the authority to approve outages of analysis tools (The OC suggests adding "under the direct control of their company"), but does not include TOPs or BAs. The OC concurs

with the clarification in IRO-002-3, and the OC further agrees that TOPs and BAs should be included.

SDT response:

The Project 2014-03 has added proposed TOP-001-3, Requirements R16 and R17 to provide Transmission Operators and Balancing Authorities with capabilities similar to those of the Reliability Coordinator.

> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
>
> Proposed TOP-001-3, Requirement R17: Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Authority R4

RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.

Operating Committee opinion

During the OCEC/Independent Expert webex, the Independent Experts explained that the objective of this requirement is to mandate the posting of a letter in the control rooms granting authority to the system operators to carry out their required tasks. While the Operating Committee believes this is a good practice, it does not believe that it rises to the level of a Standards Requirement.

SDT response:

The Project 2014-03 SDT agrees with the position of the Operating Committee Executive Committee. A letter of authority located in the Control Room is an example of good utility practice. A change to the requirements is not warranted.

Authority R5

Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

In relation to R1 above this understanding seems implicit. However, in the interest of clarity the OC would support this requirement.

SDT response:

The Project 2014-03 SDT agrees.

> Proposed TOP-001-3, Requirement R3: Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.
>
> Proposed TOP-001-3, Requirement R5: Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.
>
> Proposed IRO-001-4, Requirement R2: Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Authority R6

Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Operating Committee opinion

IRO-014-5, IRO-015-1 and IRO-016-1 describe inter RC procedures, Plans, notifications and coordination. These standards are expected to be retired and replaced by IRO-014-2 incorporating the pertinent requirements from the retiring standards. However, none of these standards explicitly include a requirement for one RC to comply with a directive from another RC.

The OC recognizes that coordination between RCs is vitally important. It is also recognized that an RC is the entity with the best understanding and situational awareness of its unique footprint. Therefore it is not believed to be beneficial for operational reliability for one RC to direct the actions of another RC. Rather, it is more appropriate to have this type of coordination documented within the requisite Joint Operating Agreements in which the appropriate assistance would be documented and understood in advance of such actions.

SDT response:

The Project 2014-03 SDT believes that proposed IRO-014-2 Requirements R3 – R6 already require Reliability Coordinators to coordinate and implement action plans even if the RC cannot agree that a problem exists or what the exact action plan is

> Proposed IRO-014-2, Requirement R3: Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.
>
> Proposed IRO-014-2, Requirement R4: Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R5: Each Reliability Coordinator that identified an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency.
>
> Proposed IRO-014-2, Requirement R6: Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identified the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) (“VRF Rehearing Order”).

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities and the status of Special Protection Systems within the Transmission Operator's Area and to obtain data outside of the Transmission Operator's Area for Facilities and status of Special Protection Systems identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor the status of Special Protection Systems that impact generation or Load could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed TOP-002-4. All of the requirements were assigned a Medium VRF.

VRF for Proposed TOP-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk

power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in proposed TOP-003-3. Four of the five requirements were assigned a "Low" VRF: Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for Proposed TOP-003-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator and proposed TOP-003-3, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the

bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: approved IRO-010-1 for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R5, has only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-001-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-001-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking actions to preserve reliability.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to act, or direct others to act, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with Operating Instructions could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of the inability to follow an Operating Instruction could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-002-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to give operators the authority to approve planned outages and maintenance of telecommunication, monitoring and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-003-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have adequate monitoring systems with emphasis on cited criteria could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

There are six requirements in proposed IRO-008-2. Four of the six requirements were assigned a "Medium" VRF: Requirements R1, R2, R3, and R6. The other requirements were assigned a "High" VRF.

VRF for Proposed IRO-008-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an Operational Planning Analysis in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement and there are no comparable requirements to compare against. It is a coordination requirement in the operational planning timeframe so this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate an Operating Plan in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify entities of roles in Operating Plans in the operational planning timeframe, in and of itself, does not directly affect

the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure that a Real-time Assessment is performed at least once every 30 minutes could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. However, that requirement combines operations planning and Real-time. This requirement only applies to Real-time which in the belief of the SDT raises the VRF to High.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of roles in plans in the Real-time environment could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R15 which is assigned a Medium VRF. The requirements are similar in that proposed IRO-008-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3 is for Transmission Operators. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of when exceedances have been mitigated will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-010-2. Two of the requirements, Requirements R1 and R2, are assigned "Low" VRFs. Requirement R3 is assigned a "Medium" VRF.

VRF for Proposed IRO-010-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R2.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the data requested does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed IRO-014-3. Four of the requirements, Requirements R4, R5, R6, and R7, were assigned a "High" VRF. Requirements R1 and R3 were assigned a "Medium" VRF. Requirement R2 was assigned a "Low" VRF.

VRF for Proposed IRO-014-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-014-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have and implement the plans and procedures, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Low VRF. The requirement is for maintenance of plans, processes, and procedures. Hence, the designation of a Low VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to maintain the plans, processes, and procedures is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other Reliability Coordinators, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.2) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R7 which has a High VRF assignment.

The requirements are similar in that proposed TOP-001-3, Requirement R7 is for Transmission Operators and Balancing Authorities while proposed IRO-014-3, Requirement R9 is for Reliability Coordinators. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-017-1. All four of the requirements have been assigned a "Medium" VRF.

VRF for Proposed IRO-017-1, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a coordination process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Medium VRF. The requirement is for following the process described in proposed IRO-017-1, Requirement R1 which is assigned a Medium VRF. Hence, the designation of a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to follow the process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved TPL-001-4 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the assessments, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate solutions, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the "default" for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R4. Those VSLs are incremental. Therefore, the SDT assigned incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R4. Those VSLs are incremental. Therefore, the SDT assigned incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. Those VSLs tried to gradate the provision of data. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity supplies the data or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT has assigned these VSLs to be binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about complying with the Operating Instruction which has a binary Severe VSL in approved IRO-001-1.1. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about informing the Reliability Coordinator which has a single Moderate VSL in approved IRO-001-1.1. The SDT believes that such a failure should be classified as binary Severe under current guidelines.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R1. Those VSLs are gradated and the SDT has followed that pattern here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R8. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity has supplied the authority or it hasn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-003-2, Requirement R1. Those VSLs tried to gradate the degree of monitoring. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is doing the monitoring or it isn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R4. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is providing adequate monitoring facilities with the particular emphasis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-008-1, Requirement R1. Those VSLs tried to gradate the performance of the Operational Planning Analysis by the number of days in a month that it wasn't available. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity performs the analysis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no comparable requirement to compare against. The SDT believes that this is a binary situation where an entity performs the coordination activity or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs gradated the notification efforts. The SDT has followed a similar path and assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R2. Those VSLs gradated the performance of Real-time Assessments based on time increments. The SDT made a similar assignment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs partially gradated the notification elements. The SDT has followed a similar path but assigned a complete set of incremental VSLs here consistent with current accepted practice.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-001-3, Requirement R15. Those VSLs are set up as a binary Severe situation but that requirement only involves notifying one entity, the Reliability Coordinator. There are potentially many more entities involved with this requirement so the SDT has set up a gradated set of VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-014-1, Requirement R1. Those VSLs present an incremental approach and the SDT has continued that approach.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement with no comparable requirement to follow. There are a number of criteria cited for the requirement and this lends itself to an incremental approach for the VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs are presented in an incremental approach. Therefore, the SDT has assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.2. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs tried to gradate things but the only differential is whether evidence was provided or not – actions themselves are covered in Severe. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity develops a plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.1. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity implements the plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed TOP-001-3, Requirement R7. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to proposed IRO-005-3.1a, Requirement R6 which has gradated VSLs and the SFT has adopted that approach here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no similar requirement in the Reliability Standards. The responsible entity either follows the process or it doesn't. Attempting to increment the effort doesn't make sense. Therefore, this VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to approved TPL-001-4, Requirement R8. In that case, the VSLs are incremental. However, the responsible entities there are dealing with many other entities. In this case, the responsible entity is dealing only with Reliability Coordinators which makes an incremental approach unnecessary due to the much smaller number of involved entities. Therefore, the VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar in nature to proposed IRO-017-1, Requirement R1. The VSL has been assigned in a similar manner – binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Violation Risk Factor and Violation Severity Level Assignments

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2014-03.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when proposing VRFs for the requirements in Project 2014-03.

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on rehearing and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are twenty requirements in proposed TOP-001-3. None of the twenty requirements were assigned a "Lower" VRF. Requirements R9 and R15 were assigned a "Medium" VRF while all of the other requirements were given a "High" VRF.

VRF for Proposed TOP-001-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking action to ensure reliability: approved TOP-001-1a for a Transmission Operator and proposed TOP-001-3 for a Balancing Authority. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take action, or to direct others to take action, could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with issued Operating Instructions could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for Proposed TOP-001-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (requirement R6) in approved TOP-001-1a which is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R7 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R7) in approved TOP-001-1a that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform other known impacted reliability entities of actions that may result in Emergencies could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R8 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-003-1 which is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to adhere to this requirement. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R9 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in ~~proposed~~approved IRO-002-~~4~~2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as ~~proposed~~approved IRO-002-~~4~~2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R10 is for Transmission Operators.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities~~,~~ and the status of Special Protection Systems~~, and sub-100 kV facilities~~ within the Transmission Operator's Area and to obtain data outside of the Transmission Operator's Area for Facilities and status of Special Protection Systems identified as necessary by the Transmission Operator, could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R10 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R4) in approved IRO-002-~~4~~2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as ~~proposed~~approved IRO-002-~~4~~2, Requirement R4 is for Reliability Coordinators while proposed TOP-001-3, Requirement R11 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor ~~facilities~~ the status of Special Protection Systems that impact generation or Load could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R11 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate within IROL T_v could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R12 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, there is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-008-1, Requirement R2 is for Reliability Coordinators while proposed TOP-001-3, Requirement R13 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure Real-time Assessments are performed at least every 30 minutes could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R13 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R14:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 which has a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to initiate the Operating Plan could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R14 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R15:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-007-0 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of actions taken to return the system to within limits could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R15 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R16:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R16 is for the Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunication, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R16 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R17:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF. The requirements are considered similar as approved IRO-002-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3, Requirement R17 is for the Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide operators with authority to approve outages and maintenance of monitoring, telecommunications, and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R17 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R18:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved IRO-009-1 that is assigned a High VRF. The requirements are considered similar since approved IRO-009-1 is about the Reliability Coordinator and proposed TOP-001-3, Requirement R18 is about the Transmission Operator. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate to the most limiting parameter when there is a difference in SOLs could lead to bulk power system instability, separation, or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R18 addresses a single objective and has a single VRF.

VRF for Proposed TOP-001-3, Requirement R19:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R19, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-001-3, Requirement R20:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capability could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-001-3, Requirement R20, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed TOP-002-4. All of the requirements were assigned a Medium VRF.

VRF for Proposed TOP-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk

power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved TOP-002-2.1b that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other impacted reliability entities of their roles does not, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-002-4, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no similar requirement to compare against. However, it is a coordination issue in the operational planning timeframe and so is being treated in a similar fashion to the other requirements in this standard. Hence, this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to submit the Operating Plan for next-day operations cannot, in and of itself, lead to bulk power system instability, separation or Cascading failures. This is an advance planning requirement, not Real-time. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-002-4, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in proposed TOP-003-3. Four of the five requirements were assigned a "Low" VRF: Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for Proposed TOP-003-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator and proposed TOP-003-3, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the

bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: approved IRO-010-1a for a Reliability Coordinator, and proposed TOP-003-3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed TOP-003-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: approved IRO-010-1 for a Reliability Coordinator, and proposed TOP-003-3 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed TOP-003-3, Requirement R5, has only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-001-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-001-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to taking actions to preserve reliability.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to act, or direct others to act, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with Operating Instructions could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-001-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. Therefore this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to inform the Reliability Coordinator of the inability to follow an Operating Instruction could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-001-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-002-4. All of the requirements were assigned a "High" VRF.

VRF for Proposed IRO-002-4, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have data exchange capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to give operators the authority to approve planned outages and maintenance of telecommunication, monitoring and analysis capabilities could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-003-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to monitor Facilities, the status of Special Protection Systems, and sub-100 kV facilities identified as necessary by the Reliability Coordinator, could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-002-4, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in approved IRO-002-2 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have adequate monitoring systems with emphasis on cited criteria could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-002-4, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

There are six requirements in proposed IRO-008-2. Four of the six requirements were assigned a "Medium" VRF: Requirements R1, R2, R3, and R6. The other requirements were assigned a "High" VRF.

VRF for Proposed IRO-008-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an Operational Planning Analysis in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement and there are no comparable requirements to compare against. It is a coordination requirement in the operational planning timeframe so this requirement is assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate an Operating Plan in the operational planning timeframe, in and of itself, does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify entities of roles in Operating Plans in the operational planning timeframe, in and of itself, does not directly affect

the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-008-1 that is assigned a High VRF. Hence, this requirement is also assigned a High VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to ensure that a Real-time Assessment is performed at least once every 30 minutes could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-008-1 that is assigned a Medium VRF. However, that requirement combines operations planning and Real-time. This requirement only applies to Real-time which in the belief of the SDT raises the VRF to High.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of roles in plans in the Real-time environment could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-008-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R15 which is assigned a Medium VRF. The requirements are similar in that proposed IRO-008-2, Requirement R8 is for Reliability Coordinators while proposed TOP-001-3 is for Transmission Operators. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify impacted entities of when exceedances have been mitigated will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-008-2, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

There are three requirements in proposed IRO-010-2. Two of the requirements, Requirements R1 and R2, are assigned "Low" VRFs. Requirement R3 is assigned a "Medium" VRF.

VRF for Proposed IRO-010-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Low VRF. Hence, this requirement is also assigned a Low VRF. This is also consistent with proposed TOP-003-3, Requirement R2.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-010-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to supply the data requested does not, in and of itself, lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-010-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are seven requirements in proposed IRO-014-3. Four of the requirements, Requirements R4, R5, R6, and R7, were assigned a "High" VRF. Requirements R1 and R3 were assigned a "Medium" VRF. Requirement R2 was assigned a "Low" VRF.

VRF for Proposed IRO-014-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-014-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have and implement the plans and procedures, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Low VRF. The requirement is for maintenance of plans, processes, and procedures. Hence, the designation of a Low VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to maintain the plans, processes, and procedures is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other Reliability Coordinators, in and of itself, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.2) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R5, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1.1) in approved IRO-016-1 that is assigned a Medium VRF. Upon reviewing the requirement, the SDT believes that it needs to be elevated to a High VRF since it is dealing with actions taken to operate during a possible Emergency situation in Real-time.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to operate as if the Emergency exists while the situation needs to be resolved could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R6, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-014-3, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement. However, it is similar to proposed TOP-001-3, Requirement R7 which has a High VRF assignment.

The requirements are similar in that proposed TOP-001-3, Requirement R7 is for Transmission Operators and Balancing Authorities while proposed IRO-014-3, Requirement R9 is for Reliability Coordinators. Hence, this requirement is also assigned a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide requested assistance could lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-014-3, Requirement R7, contains only one objective; therefore, only one VRF was assigned.

There are four requirements in proposed IRO-017-1. All four of the requirements have been assigned a "Medium" VRF.

VRF for Proposed IRO-017-1, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a coordination process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. This is a new requirement with no comparable requirement that is assigned a Medium VRF. The requirement is for following the process described in proposed IRO-017-1, Requirement R1 which is assigned a Medium VRF. Hence, the designation of a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to follow the process, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved TPL-001-4 that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the assessments, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for Proposed IRO-017-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R6) in proposed IRO-005-3.1a that is assigned a Medium VRF. Hence, this requirement is also assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate solutions, in and of itself in the planning timeframe, will not lead to bulk power system instability, separation, or Cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. Proposed IRO-017-1, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the TOP/IRO standards, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the "default" for penalty calculations.

VSLs for Proposed TOP-001-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R1. While similar, that requirement is not exactly the same as it had two clearly different objects. One of the objects has more to do with actions than the other and that part of the VSL is Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R4. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-001-1a, Requirement R6. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R7. Those VSLs are binary Severe. However, when assigning the VSLs for this requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSLs and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are those for proposed TOP-003-1, Requirement R3. Those VSLs are binary Severe. However, when assigning the VSL for the new requirement, the SDT believed that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - ~~Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.~~ There is an incremental aspect to the violation and the VSLs follow the guidelines for	The most comparable VSLs for a similar requirement are for the ~~proposed~~approved IRO-002-2, Requirement R4. Those VSLs are ~~binary Severe~~incremental. Therefore, the SDT assigned ~~a binary Severe~~ incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	incremental violations.				

VSLs for Proposed TOP-001-3, Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - ~~Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance~~ There is an incremental aspect to the violation and the VSLs follow the guidelines for	The most comparable VSLs for a similar requirement are for the ~~proposed~~approved IRO-002-2, Requirement R4. Those VSLs are ~~binary Severe~~incremental. Therefore, the SDT assigned ~~a binary Severe~~ incremental VSLs to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
	incremental violations.				

VSLs for Proposed TOP-001-3, Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R12.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R13.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved IRO-008-1, Requirement R2. Those VSLs are gradated based on missing the timing requirement. Therefore, the SDT assigned gradated VSLs to this requirement on the same basis.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R14:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R14.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-004-2, Requirement R1. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R15:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R15.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved TOP-007-0, Requirement R1. Those VSLs are gradated based on delivering an incomplete message. The SDT believed that the message needed to be complete to preserve reliability. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R16:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R16.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R17:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R17.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R8. Those VSLs are gradated based on splitting up the different approval rights. The SDT did not believe that there was any value to reliability by splitting up the approval rights. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R18:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R18.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-009-1, Requirement R5. Those VSLs are binary Severe. Therefore, the SDT assigned a binary Severe VSL to this requirement.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R19:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R19.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-001-3, Requirement R20:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R20.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The most comparable VSLs for a similar requirement are for the approved IRO-002-2, Requirement R1. Those VSLs are gradated based on a degree of incompleteness of the needed data exchange capabilities and the SDT has adopted that philosophy here as well.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are graded based on differing parts of the requirement. This requirement has only one objective – performing the analysis. That objective matches to the Severe VSL in approved TOP-002-2.1b and the SDT has proposed a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R1. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	There is a similar requirement in approved TOP-002-2.1b, Requirement R4. Those VSLs are gradated and the SDT is proposing similar treatment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-002-4, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	This is a new requirement with no comparable requirements to compare against. There is only one action to take here, to submit the Operating Plan. There is no partial compliance so the SDT assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed TOP-003-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. Those VSLs tried to gradate the provision of data. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity supplies the data or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R3. Those VSLs are binary Severe. Therefore, the SDT has assigned these VSLs to be binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about complying with the Operating Instruction which has a binary Severe VSL in approved IRO-001-1.1. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-001-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-001-1.1, Requirement R8. Those VSLs tried to gradate the situation by separating out following an Operating Instruction and informing of the inability to follow. Those actions are now separate requirements and this requirement is only about informing the Reliability Coordinator which has a single Moderate VSL in approved IRO-001-1.1. The SDT believes that such a failure should be classified as binary Severe under current guidelines.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R1. Those VSLs are gradated and the SDT has followed that pattern here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R8. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity has supplied the authority or it hasn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-003-2, Requirement R1. Those VSLs tried to gradate the degree of monitoring. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is doing the monitoring or it isn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-002-4, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-002-2, Requirement R4. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity is providing adequate monitoring facilities with the particular emphasis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-008-1, Requirement R1. Those VSLs tried to gradate the performance of the Operational Planning Analysis by the number of days in a month that it wasn't available. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity performs the analysis or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no comparable requirement to compare against. The SDT believes that this is a binary situation where an entity performs the coordination activity or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs gradated the notification efforts. The SDT has followed a similar path and assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R2. Those VSLs gradated the performance of Real-time Assessments based on time increments. The SDT made a similar assignment here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-008-1, Requirement R3. Those VSLs partially gradated the notification elements. The SDT has followed a similar path but assigned a complete set of incremental VSLs here consistent with current accepted practice.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-008-2, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-001-3, Requirement R15. Those VSLs are set up as a binary Severe situation but that requirement only involves notifying one entity, the Reliability Coordinator. There are potentially many more entities involved with this requirement so the SDT has set up a gradated set of VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-010-2, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-014-1, Requirement R1. Those VSLs present an incremental approach and the SDT has continued that approach.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement with no comparable requirement to follow. There are a number of criteria cited for the requirement and this lends itself to an incremental approach for the VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs are presented in an incremental approach. Therefore, the SDT has assigned incremental VSLs here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.2. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1. Those VSLs tried to gradate things but the only differential is whether evidence was provided or not – actions themselves are covered in Severe. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity develops a plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-016-1, Requirement R1.1. Those VSLs tried to gradate the situation. The SDT did not believe that such an exercise benefited reliability and that this was a binary situation where an entity implements the plan or it doesn't. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-014-3, Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed TOP-001-3, Requirement R7. Those VSLs are presented as binary Severe. Therefore, the SDT has assigned a binary Severe VSL here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to proposed IRO-005-3.1a, Requirement R6 which has gradated VSLs and the SFT has adopted that approach here.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This is a new requirement with no similar requirement in the Reliability Standards. The responsible entity either follows the process or it doesn't. Attempting to increment the effort doesn't make sense. Therefore, this VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar to approved TPL-001-4, Requirement R8. In that case, the VSLs are incremental. However, the responsible entities there are dealing with many other entities. In this case, the responsible entity is dealing only with Reliability Coordinators which makes an incremental approach unnecessary due to the much smaller number of involved entities. Therefore, the VSL is binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for Proposed IRO-017-1, Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	This requirement is similar in nature to proposed IRO-017-1, Requirement R1. The VSL has been assigned in a similar manner – binary Severe.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

NERC
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RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-03 Revisions to TOP and IRO Standards
TOP-001-3

Additional Ballot and Non-Binding Poll Now Open through January 7, 2015

Now Available

An additional ballot for **TOP-001-3 – Transmission Operations** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Wednesday, January 7, 2015.**

The Standards Committee (SC) authorized a waiver to shorten the comment period and additional ballot and non-binding poll for TOP-001-3. Given the holidays, the comment period has been extended to 35 days from 30 days and the ballot has been extended to 9 days from 7 days. The notice of waiver request documents presented to the SC for consideration are posted under "Supporting Documents" on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Ed Dobrowolski.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards TOP-001-3

Formal Comment Period Now Open through January 7, 2015

Now Available

A 35-day formal comment period for **TOP-001-3 – Transmission Operations** is open through **8 p.m. Eastern, Tuesday, January 7, 2015.**

The Standards Committee (SC) authorized a waiver to shorten the comment period and additional ballot and non-binding poll for TOP-001-3. Given the holidays, the comment period has been extended to 35 days from 30 days and the ballot has been extended to 9 days from 7 days. The notice of waiver request documents presented to the SC for consideration are posted below under "Supporting Documents."

Instructions for Commenting

Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated VRFs and VSLs will be conducted **December 29, 2014 through January 7, 2015.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Mark Olson.

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Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards
TOP-001-3

Formal Comment Period Now Open through January 7, 2015

Now Available

A 35-day formal comment period for **TOP-001-3 – Transmission Operations** is open through **8 p.m. Eastern, Tuesday, January 7, 2015.**

The Standards Committee (SC) authorized a waiver to shorten the comment period and additional ballot and non-binding poll for TOP-001-3. Given the holidays, the comment period has been extended to 35 days from 30 days and the ballot has been extended to 9 days from 7 days. The notice of waiver request documents presented to the SC for consideration are posted below under "Supporting Documents."

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards
TOP-001-3

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **TOP-001-3 – Transmission Operations** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Wednesday, January 7, 2015**.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	Non-Binding Poll Results
Quorum /Approval	Quorum/Supportive Opinions
80.47% / 72.43%	79.47% / 73.58%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Ed Dobrowolski.

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Ballot Results	
Ballot Name:	Project 2014-03 TOP-001-3_Additional_Ballot
Ballot Period:	12/29/2014 - 1/7/2015
Ballot Type:	Successive
Total # Votes:	305
Total Ballot Pool:	379
Quorum:	**80.47 % The Quorum has been reached**
Weighted Segment Vote:	72.43 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	56	0.691	25	0.309	0	2	22
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	0	3
3 - Segment 3	83	1	43	0.717	17	0.283	0	7	16
4 - Segment 4	30	1	14	0.609	9	0.391	0	0	7
5 - Segment 5	82	1	42	0.667	21	0.333	0	4	15
6 - Segment 6	52	1	30	0.714	12	0.286	0	2	8
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**6.9**	**201**	**4.998**	**87**	**1.902**	**0**	**17**	**74**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES POWER MARKETING)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	

1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jason Snodgrass)
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine		
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (- I support MRO NSRF)
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour		
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments)
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support MRO NSRF comments and SPP Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas E. Foltz, American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	

1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's Comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES & NRECA)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	

3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN		
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group, Colorado Springs Utilities)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO MSRF)
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards

				Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid Group Comments)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support MRO NSRF and SPP comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (duke)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's Comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
				SUPPORTS THIRD PARTY

4	Consumers Energy Company	Tracy Goble	Negative	COMMENTS - (Gerald Farringer)
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD)
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney		
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC's Comments)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's Comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	

5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP and MRO NSRF)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
				SUPPORTS

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	THIRD PARTY COMMENTS - (ACES and GTC)
5	Northern Indiana Public Service Co.	Michael D Melvin		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz AEP)
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Abstain	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	

10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Non-Binding Poll Results

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2014-03 TOP-001-3
Poll Period:	12/29/2014 - 1/7/2015
Total # Opinions:	271
Total Ballot Pool:	341
Summary Results:	79.47% of those who registered to participate provided an opinion or an abstention; 73.58% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jason Snodgrass)
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine		
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour		
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		

1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please see NPCC RSC comments)
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)

3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group, Colorado Springs Utilities)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid group comments)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn		

NERC

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Gerald Farringer)
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD)
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney		

4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC's comments)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Negative	COMMENT RECEIVED

NERC

5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cowlitz PUD)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	EDP Renewables North America LLC	Heather Bowden		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	

5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Abstain	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	

6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)

7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (40 Responses)
Name (26 Responses)
Organization (26 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (35 Responses)
Question 1 Comments (35 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
Regarding Requirement R13, there is concern that an operator will be obligated to perform the assessment. Given that the Rationale for Requirement R13, although not auditable, supports the Requirement's wording, suggest revising the Rationale Box to read: The new requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan may describe how to perform the Real-time Assessment. It would also be helpful to confirm that at times no actions may be required if system conditions have not changed within the thirty minute window and that previous contingency analysis or assessments may be used to perform the Real time Assessment for subsequent hours. A suggested revision to Requirement R13: R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-Time Assessment every 30 minutes. And for Measure M13: M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence. Appropriate wording consistent with this should be added to Section F. Associated Documents.
Individual
Daniel Duff
Liberty Electric Power LLC
No
The Operating Instruction should be identified as such by the issuing entity. Not identifying an Operating Instruction will lead to confusion over whether the instruction is a Marketing Instruction or an Operating Instruction. For example, a unit being released from the grid can self-dispatch if the release is for economics. But if the release is considered an Operating Instruction due to conditions of which the GOP is not aware, a violation could occur. Suggest adding one word - Identified - to R3 prior to the term Operating Instruction.
Group
Oklahoma Gas & Electric
Terri Pyle
No
TOP-001-3 R1 & R2 – We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate the threat of double jeopardy. We don't see that happening with the terminology being proposed. We propose to either continue to use the word "address" or replace it with "support". Rationale Box for R3 – In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line. R5 – Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure. R6 – Change 'that' in the 3rd line to 'its' for consistency with Requirement R4. Rationale Box for R7 – In

the Rationale Box for Requirement R7, delete the apostrophe in front of ‘This’ at the start of the 2nd sentence and also change ‘changes’ to ‘change’ in the same sentence. R9 – If the SDT’s intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase ‘and unplanned outages of 30 minutes or more’ need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn’t the SDT’s intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: ‘Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.’ R10 – We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the ‘as necessary’ in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the ‘identified by the Transmission Operator’ in R10 as follows: ‘Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:’ Change ‘voltages’ in Requirement 10, Part 10.2 to ‘voltage’. Make the same change in the Measure as follows: "Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltage, and flow data for Facilities and the status of Special Protection Systems as necessary to determine any identified System Operating Limit (SOL) exceedances within its Transmission Operator Area. R11 – Change ‘Load-interchange balance’ to ‘generation-Load-interchange balance’ which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11. VSLs for R8 – If the SDT has not changed its position on the inclusion of ‘other’ in this requirement, usage by the way which is consistent with that in Requirement R7, then ‘other’ needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8. VSLs for R16 and R17 – Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted. We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well.
Individual
Thomas Foltz
American Electric Power
No
R9: AEP disagrees with requiring notification of every planned and unplanned outage of 30 minutes or more, especially since the requirement could be interpreted as applying to the individual RTU’s themselves, and irrespective of their impact to the reliability of the BES. AEP believes the proposed language is overly prescriptive, does not accomplish the desired results of the SDT, and provides no benefit to the reliability of the BES. BAs and TOPs should be interested in knowing that they have quality data coming in, i.e., knowing whether or not the data is valid. There is no reliability benefit in requiring notification of every outage of every piece of equipment producing that data. PJM, for example, is in no position to know or determine how or if an individual RTU impacts reliability, or even the quality of the solution of a State Estimator. AEP believes it is far more important to know the *quality* of data feeding the applicable systems (for example, a state estimator), rather than the status of each piece of equipment in the systems which provide that data. AEP requests the drafting team articulate what reliability benefit they believe is gained by providing the status of individual pieces of equipment within R9. The phrase “all planned outages, and unplanned outages of 30 minutes or more” could have multiple interpretations. One possible interpretation is that the 30 minute threshold only applies to an unplanned outage, thereby inferring that notification be made for each and every planned outage, regardless of its duration. Another possible interpretation is that the 30 minute threshold is used for both planned *and* unplanned outages. Please clarify this phrase to make it clear which outages the 30 minute threshold applies to. The text “between the affected entities” seems to imply inter-connections, even though it does not read as such earlier in

R9 (known impacted interconnected entities). AEP recommends changing the language “all planned outages, and unplanned sustained outages” to simply say “all significant outages” and allow the TO and TOP to determine what is significant to the reliable operation of the BES. AEP voted affirmative on draft 3, a draft we consider superior in content to the draft currently proposed. AEP has chosen to vote negative on draft 4, driven by our objections to the latest revisions to R9, as expressed above.
Individual
Chris Scanlon
Exelon
Individual
Denise M. Lietz
Puget Sound Energy
No
The use of the word "maintain" instead of "address" raises the same issues as the word "ensure" in the previous drafts of this standard - if a reliability issue arises, an enforcement entity might find a violation of requirements R1 and R2 simply because an entity failed to "maintain the reliability" of its area (whether or not the entity’s operators took appropriate action to respond to the issue). In addition, the current draft does not address the burden associated with the need to demonstrate compliance with each Operating Instruction under requirement R3. I have previously commented on this issue and I continue to believe that the approach taken to Operating Instructions under the COM-002 standard more appropriately balances compliance burden with reliability needs.
Individual
Joshua Smith
Oncor Electric Delivery LLC
No
Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor’s suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States: R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] 10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10.2 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor’s recommendation is to keep the existing 30 minute time limit.

Group
Dominion
Connie Lowe
Yes
4. Applicability: Suggest that “4.5”be struck as Load Serving Entity was deleted from the applicability list of entities. Dominion suggests that the Rationale for Requirement R13: be modified to state, “…and the timeframe is copied from the approved IRO-008-1, Requirement R2 for consistency.”, as the language is not verbatim from approved IRO-008-1 Requirement 2. M5 - Suggest the “(s)” behind Balancing Authority be removed to match R5.
Individual
Scott Bos
Corn Belt Power Cooperative
Individual
David Jendras
Ameren
No
In our opinion, changes in this version were not significant and the drafting team has not addressed our concerns. (1) We have concerns on what constitutes "Operating Instructions", and over how an entity is to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up TOP's to an very burdensome way of documenting compliance. (2) We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. (3) We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. (4) Over the years, the industry has clearly learned what a “Reliability Directive” means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able to locate any such information in the Reliability Standard itself, nor does the standard give guidance on when there are no BES events for the period being audited.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM supports the standard and appreciates the changes made by the SDT.
Individual
Scott Berry
Indiana Municipal Power Agency
No
IMPA does not agree with the use of Operating Instruction within this standard and does not agree with the SDT comments on how the RSAW will be used to “constrain” the potential amount of data an entity will need to provide to an auditor. NERC standards should be able to stand alone and not depend on RSAWs for guidance, especially since entities are audited to the requirements within a standard and not the RSAW. The RSAW states that auditors are encouraged to monitor compliance during the most “critical” events on the entity’s system. Once an auditor states that all Operating Instructions are critical to the BES, then data for all Operating Instructions will need to be supplied to the auditor or a listing of the Operating Instructions for the compliance period with a follow up of evidence (the entity still needs to keep all the evidence for every Operating Instruction for the compliance period just in case that is the one selected). By changing the “reliability directive” wording to “Operating Instruction” within requirements R3 and R5 of TOP-001-3, the SDT has

increased the administrative burden on entities who receive Operating Instructions from their TOP and BA. Once again increasing the administrative burden on entities is the opposite theme of the RAI program which has a goal of helping the industry to concentrate on the “risk” to the BES.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC
No
R10.2 – CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “…identified as necessary by the Transmission Operator…” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. – CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.
Individual
Brett Holland
Kansas City Power and Light
Individual
Gerald Farringer
Consumers Energy Company
No
Comments: M3 and M5 are over reaching in requiring: In such cases, the Balancing Authority, Generator Operator, and Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator’s Operating Instruction. In the case of generating equipment this can and often is conditional with operating constraints under certain conditions. There may not be specific rules written out to cover all conditions. This is often within the authority of the plant operator concerning what can be done safely with the equipment. This was not an evidence requirement in the current standards and does not need to be one now. We would be in favor of striking the above in both M3 and M5.
Individual
Russ Schneider
Flathead Electric Cooperative
No
The change related to sustained outage being one more than 30 minutes seems tight. 30 minutes isn't very long for an outage.
Group
Seattle City Light
Paul Haase
No

Seattle City Light (SCL) appreciates the efforts made by the Standard Drafting Team to respond to comments from industry and create a quality Standard that is clear and complete. Considerable progress has been made from earlier postings. Some areas remain for improvement. Specifically, SCL diagrees with the R13 requirement for ensuring a real time assessment each 30 minutes, and believes a two-hour requirement to be sufficient and consistent with EOP-008. If 2 hours is too long, SCL urges consideration of a 60 minute requirement, as recommended in an earlier posting. A 30 minutes requirement in our opinion does not add enough reliability benefit to be worth the additional cost, effort, and compliance risk. SCL also continues to recommend that R19 and R20 be deleted from TOP-001-3, as discussed previously. Finally, SCL is concerned with the growing number of BA-specific requirements (R11, R17, and R20) included a TOP-area Standard. While we understand the difficulty of aligning all requirements within the appropriate Standard area (BAL, TOP, etc), we urge extra effort be made to maintain and promote such alignment more than has been done to date. For example, INT-009-2 included BA requirements that do not properly belong in that Standard but were included out of expedience and a lack of willingness to develop an appropriate new SAR. SCL recommends reconsidering the need to include BA-only requirements within a TOP-family Standard, and alternative approaches to addressing these reliability needs in a different Standard.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC
No
R10.2 – CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “…identified as necessary by the Transmission Operator…” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. – CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.
Individual
Donald E Nelson
Massachusetts Department of Public Utilities
Individual
Erika Doot
US Bureau of Reclamation
No
Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3. The drafting team's response to concerns about use of the term "Operating Instruction" rather than reliability directive include "The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered" and "Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC’s acceptance of the standards. In the FERC NOPR, it was made clear that the concept of a special type of communication for

Emergency situations was not considered acceptable. Operating Instructions issued to generators are not intended to damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers)." Reclamation respectfully disagrees with the drafting team's interpretation. Reclamation believes that FERC Order directed NERC to define "directive" rather than extend the scope of the standard to all communications between entities regarding bulk electric system operations. The order stated that the proposed standard had defined "transmission operator directives only in emergencies, not normal or pre-emergency times." Reclamation agrees with FERC that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements)." In Reclamation's opinion, the FERC order only directed NERC to better define the term "directive" and allow directives to be issued during normal operations as well as pre-emergency and emergency situations. Reclamation does not believe that FERC required the standard to apply to all non-emergency conversations between GOPs, BAs, and TOPs, with mutually-agreed upon operating plans resulting from these conversations like the COM updates. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators, and without this understanding Transmission Operators should not have authority for every operating instruction to be mandatory. Reclamation believes that Balancing Authorities and Transmission Providers should be granted wide latitude to issue "directives," which could be defined as "mandatory operating instructions to address transmission system concerns," but directives should be clearly identified by the transmission operator as directives to inform the recipient of the critical nature of the instruction. As written, the standard would instead apply to all operating instructions in all situations, and essentially would allow transmission operators to dictate instructions without understanding competing safety, equipment, regulatory and statutory (including environmental) concerns of generators. This is likely to degrade BES reliability because generator operators will no longer understand the criticality of transmission operator instructions identified as "directives." Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked unless the Transmission Operator describes a mandatory instruction as a Reliability Directive. Reclamation appreciates the clarifying language changes in R16, M16, R17, and M17.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration, LP
No
Ingleside Cogeneration L.P. (ICLP) believes that the project team has found an excellent resolution to the issue surrounding “sub-100 kV” and “non-BES” element data. By relying on other standards such as FAC-011-2 – which allows the Reliability Coordinator to dictate that the TOP must consider such facilities while developing their SOLs – the intent is still captured in a binding manner. In addition, NERC’s BES exception process allows the forced registration of critical facilities, which clearly applies to those that would affect a System Operating Limit. The TOP still has the obligation and authority to derive/monitor every SOL, but is not subject to the opinion of a CEA who may think that the criteria used is insufficient. Unfortunately, no such insight has been employed to defuse the standoff related to the execution of “Operating Instructions”. The issue caught FERC’s attention originally as the term “Reliability Directive” was used in the submission of TOP-001-2 – which only applied to situations where an Emergency was declared. The Commission felt that instructions issued by a BA/TOP during near-emergency and normal operating conditions should also be mandatory, which the in-effect version of TOP-001 does not preclude. (It uses the generic un-capitalized term “reliability directive” which can apply to most any communication requiring action by the recipient.) The attempt to clarify the proper situations where a reliability directive can be used, and the evidence required to demonstrate compliance, has led to this impasse. ICLP believes that the way TOP-001-3 is written now, a GOP will be expected to capture the fact that every Operating Instruction was performed, even in low-risk situations where status or routine action is requested. This works against the concept of risk-based compliance and adds an administrative burden that is disproportional to the expected benefits. ICLP believes there is an acceptable alternative. The project team can lessen the severity of the improper execution of an Operating Instruction as compared to a Reliability Directive. This would mean that any instruction not identified by the BA or TOP as a

Reliability Directive would only carry a Low VRF if not executed properly – perhaps a High VRF if an EOP-004-2 defined Event took place as a result. Furthermore, the lack of documentation should not work against the recipient of an Operating Instruction, but would allow for mitigating considerations if a good faith attempt was made in its execution. This would encourage the GOP (in our case) to diligently capture every Operating Instruction, but would not lead to a violation when an understandable oversight took place.
Individual
Leonard Kula
Independent Electricity System Operator
No
1. We continue to have serious concerns over the proposed retirement of TOP-004-2 Requirement R4 without having some of the requirements in TOP-001-3 revised to address the reliability need for confirming and re-establishing valid SOLs/IROLs in an unknown or unstudied state. We believe that there are times when, following some power system event, when there are no derived set of limits – particularly transient stability limits. We believe that the revised TOP standards do not compel an entity to derive limits following such events within an acceptable time frame. That direction was clearly specified in the existing TOP-004-2 R4: R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. We believe that removal of this requirement, without adequately and clearly replacing it, significantly diminishes reliability. We submit the following detailed comments for consideration by the SDT: a. The SDT's response to our previous comment suggests there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. We are unable to find a requirement in the standard that stipulates the Operating Plan shall have guidance to adjust the limit until a new set of limits are analyzed and determined. This requirement doesn't appear to exist. b. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The above response addresses SOL exceedance only; but the issue we raised is on the need to re-establish SOLs themselves, which may not already exist for the conditions encountered. How does an entity know if it has exceeded an SOL if an SOL was not previously developed or is invalidated by the prevailing conditions? c. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to an unplanned system event. The SDT's response suggests that the concept of confirming and re-establishing SOL's is covered in the entities' Operating Plan. An Operating Plan, consistent with the NERC definition, is general and predictive in nature and by itself does not mandate the confirmation or re-establishment of limits when in an unstudied state. The concept of confirming and re-establishing SOL's for the prevailing condition is only captured in the SOL Exceedance White Paper under the "Stability Limit Exceedance" section as follows: "Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid." This sentence is presented in a standard requirement language. We do not understand why this is not stipulated in the standard itself such that it becomes an enforceable requirement to address the potential reliability gap created by retiring TOP-004-2 Requirement R4. Having this language in a whitepaper does not make this mandatory. 2. We offer the following comments on three requirements in TOP-001-3: i. R7: We do not agree with the added qualifier "within its Reliability Coordinator Area" since we believe that all TOPs need to assist their neighbor TOPs regardless if they are in the same RC area. We propose to remove this qualifier from R7. ii. R10: We understand the intent of the proposed changes to Parts 10.1 and 10.2, but these changes have made the two parts confusing and inconsistent. From a reliability standpoint, it is intuitive that a TOP needs to monitor all Facilities within its TOP area that may have an impact on SOLs/IROLs. Part 10.1 is unclear on this whereas Part 10.2 is more specific on the parameters of the concerned Facilities. We suggest adding the word "all" before "Facilities" in Part 10.1. iii. R11: This requirement is redundant with BAL-002 since the

latter already requires a BA to assess all contingencies – which should include SPS operations resulting in generation and/or load reduction, to determine its reserve requirements. We suggest removing R11.
Group
ISO RTO Council Standards Review Committee (SRC)
Greg Campoli
No
Requirement R11, as proposed, states, “Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.” The SRC suggests that Requirement R11 is duplicative of requirements and obligations placed on Balancing Authorities in the BAL Standards and, therefore, suggests deletion of Requirement R11.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
ATC recommends that the SDT consider removing the following language from the proposed “Real-time Assessment” definition: “known Protection System and Special Protection System status or degradation,” The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) --- Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a protection system failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13.
Group
Con Edison, Inc.
Kelly Dash
No
Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.
Group
National Grid
Michael Jones
No
Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be

granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. • Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.
Group
Duke Energy
Michael Lowman
No
R1&R2: Duke Energy still has concerns regarding the wording associated with R1 and R2. The SDT stated in their consideration of Duke Energy comments that, "Specific actions for specific situations will be covered under the applicable standards." Our fear is that the language can still be viewed as a failure to act or a failure to maintain. Duke Energy understands and agrees, through informal discussions with the SDT, that the intent of R1 and R2 is that the BA and TOP must take some action in order to maintain the reliability of the BES and not whether the BA or TOP succeeded in said action. R9: Duke Energy agrees with the removal of "sustained" and the addition of a timing requirement for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. However, would like the SDT to provide a response to the following question, If the primary channel (RTU, etc.) is out of service and the backup is working properly, then is the expectation for the BA and TOP to notify the RC and other entities affected that the primary communication channel is out service? (Even though monitoring, assessment capabilities, etc. have not been affected). Duke Energy understands and agrees, through informal discussions with the SDT, that if back-up communication channels from the BA and TOP are still providing data then there is no need for communications to the RC and others affected as described in R9. Associated Documents (SOL Exeedance document): Duke Energy requests clarification on the compliance ramifications of the Associated Documents section. Upon our review of Appendix 3A of the NERC Rules of Procedure, Associated Documents are not included in the Appendix, and thus an entity would not consider the section to be an enforceable part of the standard for compliance purposes. We do not feel that including a URL, rather than attaching the entire document to the standard clears up any confusion the industry may have on this issue. Duke Energy maintains that this document could be viewed as an expansion of what is currently considered to be an SOL, and feels that this document should be viewed as purely a Guideline/Technical Basis document as is currently labeled in other NERC standards (see CIP-004-7).
Individual
Daniel Duff
Liberty Electric Power LLC
No
No, the SDT should have further defined "reliability directive" instead of punting and simply replacing it with the term "Operating Instruction".
Individual
Jason Snodgrass
Georgia Transmission Corp
No
(1) GTC requests the drafting team to develop separate requirements for the DP to comply with Operating Instructions received by the TOP and BA which is consistent with NERC's Functional Model relating to real-time switching activities at non-BES facilities. By making this change, the requirements will be made clearer that the Operating Instructions that the DP receive from the TOP with respect to the defined term Operating Instruction, correspond to switching non-BES facilities that "impact" the output of an Element of the BES (shed or shift load). GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP dispatch center that does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). The aforementioned comments relating to DP switching non-BES facilities provides additional support of why the DP should be ungrouped with the BA and GOP which may own and operate BES facilities. This separation of BES vs non-BES associated with implementing Operating

Instructions reduces the current ambiguity for those NERC registered DPs that are also registered as Transmission Owners but are not registered as Transmission Operators with respect to requirements R3 and R5. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: • Each Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator to reduce voltage, shed load, shift load, and/or implement system restoration plans on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. • Each Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority to reduce voltage, shed load, or shift load on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) If however, the current draft standard passes this ballot GTC would greatly appreciate for the Standard Drafting team to expand the Rationale for Requirement R3 corresponding with the DP by inserting the following language: As identified in the NERC functional Model, Distribution Provider's must perform switching tasks to implement voltage reduction, load shed, or as part of a system restoration plans as directed by the Transmission Operator or Balancing Authority. (3) This Standard does not apply to a Transmission Owner; will the drafting team confirm GTC's assumption that the recipient field personnel of an Operating Instruction who performs the switching inside "transmission stations" are assumed to be handled by the TOP via R1? (4) The recipient entities of Operating Instructions performed in the field that do not own control centers will rely on the operator logs and voice recordings of the issuing entities as compliance evidence. Those entities (issuing vs recipient) which may have different data retention periods for compliance enforcement protection increases compliance risk to recipient entities that have zero control over the data. This risk can be mitigated by incorporating a reasonable data retention period into the requirements that are consistent with compliance enforcement practices. It should be noted, that the 90 day retention period under section C of this standard does not align with any compliance enforcement Regional Entity expectations and only adds confusion.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Thank you standard drafting teammates for all of your work on this complex standard! R13 Comment: R13 requires that a Real-time Assessment is performed at least once every 30 minutes. We believe that this is in conflict with EOP-008 which allows for a two hour transition period to back-up control center. How does the standard drafting team anticipate that an entity that is failing over to a back-up control center is to maintain compliance with this requirement? This requirement needs to be modified to make sure it is consistent with EOP-008. General Comment: We re-submit our comment concerning the use of the word "maintain" which has much the same implications as "ensure". We concur that entities must act timely and prudently for the reliability of the BES, but entities should not be unduly held accountable for system conditions outside their control that lead to reliability issues of the BES. We favor the word "address" and "address reliability" to "maintain" and "maintain reliability." The fact that a reliability issue or even a black-out has occurred is not sufficient to prove that entities were not appropriately acting. We must avoid requirement language that attaches liability just because a reliability event occurs.
Group
SPP Standards Review Group
Robert Rhodes
No
TOP-001-3 R1 & R2 – We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate the threat of double jeopardy. We don't see that happening with the terminology being proposed. Rationale Box for R3 – In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line. R5 – Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure. R6 – Change 'that' in the 3rd line to 'its' for consistency with Requirement R4. Rationale Box for R7 – In the Rationale Box for Requirement R7, delete the apostrophe in front of 'This' at the start of the 2nd sentence and also change 'changes' to 'change' in the same sentence. R9 – If the

SDT's intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase 'and unplanned outages of 30 minutes or more' need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn't the SDT's intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: 'Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.' R10 – We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the 'as necessary' in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the 'identified by the Transmission Operator' in R10 as follows: 'Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:' Change 'voltages' in Requirement 10, Part 10.2 to 'voltage'. Make the same change in the Measure. R11 – Change 'Load-interchange balance' to 'generation-Load-interchange balance' which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11. VSLs for R8 – If the SDT has not changed its position on the inclusion of 'other' in this requirement, usage by the way which is consistent with that in Requirement R7, then 'other' needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8. VSLs for R16 and R17 – Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted. We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well. Implementation Plan Split the 2nd paragraph on the 4th page into two sentences. Do this by replacing '...SW Outage Report, and this implementation plan...' with '...SW Outage Report. This implementation plan...' at the end of the 3rd and the beginning of the 4th lines of the paragraph. In the paragraph under General Considerations on page 4, delete the 's' on 'Requirements R5' at the end of the 3rd line. In the 1st paragraph under Implementation Plan for Definitions on page 8, replace 'definitions' in the 4th line with 'definition.' SOL Whitepaper The '3.' at the top of page 3 should be '4.'. Split the 1st sentence of the paragraph immediately following '4.' above into two sentences by making the following change in the 3rd line of that paragraph. Replace '...Requirement R2 sub-requirements, the assumption being that...' with '...Requirement R2 sub-requirements. The assumption being that...'. In the last line under the first 3 on page 4, change 'limit' to 'limits'. Replace 'Owner' at the top of page 6 with 'Owner's'. Capitalize 'process' at the end of the last line of the Operating Process definition on page 10. NOPR Issues The language quoted on page 2 for IRO-008-2, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 2 for IRO-008-2, Requirement R4 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 3 for IRO-002-4, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 7 for TOP-001-3, Requirement R11 is not consistent with the language currently posted for comment and ballot. The language quoted on page 7 for TOP-001-3, Requirement R13 is not consistent with the language currently posted for comment and ballot. The language shown is actually Requirement R11 of the posted version. The reference to proposed IRO-014-2, Requirement R1 on page 20 should actually be to IRO-014-3. Part 1.1 of IRO-017-1, Requirement R1 shown on page 20 is missing the 1.1 designation. The language quoted on page 21 for TOP-003-3, Requirement R5, Part 5.3 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 21 for IRO-010-2, Requirement R3, Part 3.3 is not consistent with the language posted in the final ballot package of October 10, 2014.
Group
Bonneville Power Administration
Andrea Jessup
No

BPA’s primary concern is with the way Requirement R8 is written. It requires BPA to inform the RC and any impacted TOP’s and BA’s of an actual or expected operating condition that results in or could result in an Emergency. Emergency is defined in the NERC Glossary as: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System” BPA could interpret this to mean that our dispatchers should call the RC anytime any 115kV line anywhere on BPA’s system is threatened by fire, wind, ice, or other conditions. BPA is also concerned about having to inform these other parties of “expected operating conditions …that could result in an Emergency.” It is not clear to BPA how an auditor will interpret this. BPA is concerned that, given how broad the definition of “Emergency” is, we might violate R8 for not anticipating a particular operating condition or its full consequences. Again, “Emergency” does not merely refer to a WECC-wide stability event like September 8. This is written such that it includes a simple trip of a 115kV line.
Group
MRO- NERC Standards Review Forum
Joe Depoorter
No
: The NSRF cannot support R1 and R2 as written within the proposed TOP-001-3. The NSRF believes that as written, these Requirements are a catch all, ambiguous, and not measurable. FERC Order 693, section 253 states, “…compliance will in all cases be measured be determining whether the party met or failed to meet the Requirement….” The NSRF does not understand what is being required by the TOP and BA, respectfully. Granted, the SDT wants a TOP and BA to “maintain the reliability of its Area via its own actions or by issuing Operating Instructions”. The NSRF views this as what a TOP and BA should be doing at all times. But in order for a TOP or BA to show proof of compliance, the industry needs to know what is required of them? The SDT has not provided any relief to the TOP and BA as we move into risk based compliance activities. The NSRF has referred to the Standards Process Manual to point out to the SDT that Standards Process Manual section 2.4 describes a “Results Based Requirement” as “Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective and not how that objective is achieved”. In FERC’s Order regarding NERC’s Five-Year Performance Assessment [149 FERC ¶ 61,141, P 70 (2014)], the Commission recently highlighted the importance of improving consistency: “The Commission recognizes and supports NERC’s efforts to increase consistency and promote coordination across the ERO Enterprise. A key element of consistency is the transparency of the ERO Enterprise’s processes and its outcomes. Improved consistency and coordination helps to clarify the roles and responsibilities of NERC and the Regional Entities and should lead to more efficient and uniform work practices. Specifically, we believe that a focus on achieving consistent compliance and enforcement outcomes (e.g., monetary penalties, registration decisions, and consistent understanding of Reliability Standard requirements) while not equating consistency with a “lowest common denominator” approach would provide the greatest benefit to registered entities.” As written, R1 and R2 do not provide a “consistent understanding of Reliability Standard requirements”. The NSRF has even given proposed rewrite of “A possible rewrite of R1 and R2 to read: ”Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance “. The SDT replied that “The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal - either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement”. The NSRF does not agree with the “spirit” that the SDT believes is the intent of the Requirements. If the SDT believes that the “TOP and BA shall maintain the reliability of its area by the means it has at its disposal”, then that should be clearly stated within R1 and R2. The NSRF believes that section 253 of FERC Order 693 could then be adhered, too. The NSRF recommends that the SDT consider removing the following language from the proposed “Real-time Assessment” definition: “known Protection System and Special Protection System status or degradation,” The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be

provided through internal systems or through third-party services.) Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a Protection System failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13. What happens when the analysis cannot be accomplished within 30 minutes due to other emergency conditions? Whereby the Entity is reacting to a priority situation? With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform with this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the “situational awareness” because they will not know “known Protection System and Special Protection System status or degradation…” per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words “have situational awareness” in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. The NSRF would also wish to point out that the SDT may believe that an Entity’s RTCA may run every several minutes and thus fulfilling the 30 minute requirement. An Entity cannot be directed to have an RTCA and most RTCA systems, do not function properly if all the data points are not provided, ie, transmission lines out of service due to severe weather, thus unable to provide the required “situational awareness”.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Group
ACES Standards Collaborators
Ben Engelby
No
(1) Requirements R1 and R2 are vague, overly broad, and duplicative of other requirements and will be difficult to demonstrate compliance with and as a result may distract System Operators from their reliability mission. If there is a disturbance on the transmission system, there could be a potential violation of R1 and R2 because the TOP/BA did not “maintain reliability” of its area regardless whether is actions were appropriate or not. This requirement is very subjective and will allow auditors or investigators to interpret a system operator’s actions after-the-fact to determine if they acted appropriately. There is nothing in these requirements that allow for a reasonable measure of performance. The Compliance Enforcement Authority will evaluate whether actions were taken, Operating Instructions were issued, and whether or not reliability was maintained. There could be a

violation whenever a disturbance occurs in the TOP/BA area including events beyond their control such as tornadoes or hurricanes, as reliability was not maintained. These requirements are duplicative with many other requirements. For example, failing to initiate an Operating Plan to mitigate an SOL exceedance in R14 is failing to take action or issue Operating Instructions to maintain reliability. While the RSAW's do attempt to limit the burden of proving compliance with every Operating Instruction by instructing auditors to monitor compliance during events, RSAWs are simply guidance documents that an auditor is not obligated to follow. Thus, a TOP and BA must be able to prove compliance by retaining every Operating Instruction and that it acted in response to every operating threat. This is a tall order that will distract System Operators from their reliability mission and as a result be a detriment to reliability. While System Operators are already tasked with logging actions and information throughout the day, their standards for documenting information likely are not at a level that would be auditably compliant. Thus, System Operators will have to focus time and energy that should be focused on Operating the system with writing auditably compliant logs. A better solution would be to revert these requirements back to the authority requirements of the existing standards. The data retention section of this standard exacerbates the issue by requiring evidence that is not an operator log or voice recording to be retained for up to two calendar years. What other evidence does the drafting team foresee will be used to demonstrate compliance? These requirements need to be revised to include a reasonable measure of performance and the VSL table should be modified to account for instances where contributing factors led to reliability not being maintained. (2) Requirements R1 and R2 do not line up with the functional model. A TOP is obligated per R1 "to act to maintain the reliability of its Transmission Operator Areas via its own actions or by issuing Operating Instructions." This means that a TOP must respond to all reliability threats including those that are not its responsibility. Consider a large generating plant trips and frequency declines significantly but there are not SOL or IROL violations or voltage violations. In other words, the transmission system is within operating limits with the exception of frequency. The TOP should not act because the BA should be acting to recover frequency. In fact, if the TOP does act, it likely will be detrimental to reliability. However, the TOP would be in technical violation of the requirement because it did not act and or issue Operating Instructions in response to a reliability threat within its Transmission Operator Area. (3) Requirements R3, R4, R5, and R6 should be modified in several ways. First, we disagree with the classifications of High VRF and Severe VSL for failing to comply with an Operating Instruction in all instances. Failing to follow an Operating Instruction during routine operations, is unlikely "to directly cause or contribute to Bulk-Power System instability, separation or a cascading sequence of failures" as required by a High VRF. As an example, the failure to implement the Operating Instruction correctly in the Arizona-Southern California did not directly cause the outage as it was not a root cause. Rather it was the initiating action and other standards violations were required to cause the blackout. The VRF should be reduced to Medium. Second, the VSL table should be graduated to allow for instances of both Operating Instructions issued during Emergencies and Operating Instructions issued during non-Emergencies. Finally, the requirements should be modified to take into account Emergency and non-Emergency conditions. Failing to implement an Operating Instruction during a non-Emergency does not pose the same risk to BES reliability as failing to implement an Operating Instruction during an Emergency. Failing to implement an Operating Instruction during a non-Emergency would require other standards violations to cause a blackout. Under the current draft, all failures to comply with Operating Instructions could result in fine of $1 Million per day, per violation. This does not seem reasonable, especially in the instance of a small generator or Distribution Provider that would have limited impact on reliability from failing to implement varying types of Operating Instructions. (4) Requirement R7 has reverted back to comparable Emergency procedures, which the drafting team has acknowledged in the rationale box of the previous posting as "impossible to measure." Has the drafting team determined a way to measure and if so has it been documented? (5) Requirement R8 should be limited to known impacted Balancing Authorities and known impacted Transmission Operators "within the RC Area." This modification would be consistent with R7. As currently written, R8 requires a TOP to inform all other BAs and TOPs in the Interconnection, as they would be impacted entities. Further, the percentages in the VSL do not accurately reflect the amount of entities that would need to communicate. The metric of 15 percent or less of the impacted TOPs assumes that 10 or more entities should be notified. In an Emergency, the RC and neighboring entities should be notified, as system operators should be focused at mitigating the conditions leading to the Emergency. The RC is responsible for wide-area reliability. (6) Requirement R9's VSL table needs to be modified. As written, a Severe VSL will result if a BA/TOP does not contact four or

more known impacted interconnected entities. The requirement does not state how many entities must be contacted. If the BA/TOP contacts its RC, the burden should shift to the RC to coordinate with other impacted entities. The requirement needs to be clarified and VSL table should be modified. (7) Requirement R10 has improved with the removal of non-BES facilities. (8) Requirement R11 is duplicative with many of the NERC BAL standards. A BA is expected, as required by these BAL standards, to monitor the load-interchange balance and frequency its own area to calculate ACE as part of its efforts to maintain compliance with CPS1, CPS2, DCS, and eventually with the Balancing Authority ACE Limit, defined within NERC Standards BAL-001-2, and currently on file with FERC. Moreover, several other BAL requirements identify criteria that a BA must use to properly calculate its ACE and identify the need for redundant mechanisms to monitor the ACE components. (9) Requirement R15 is duplicative with R8. Both requirements address the TOP notifying the RC of actual operations that could result in an Emergency. Actions taken to return the system to within limits when a SOL has been exceeded could fall into this category. R15 should be struck. (10) The purpose statement is vague and overly broad and should be revised. The purpose of the Energy Policy Act of 2005 is to ensure reliability operation which by definition includes preventing instability, cascading, and uncontrolled separation. Thus, this is the purpose of the reliability standards as a whole. Furthermore, the way the purpose statement is written implies that instability, uncontrolled separation, and cascading may not adversely impact the interconnection with the "that adversely impact the reliability of the Interconnection." How would instability, uncontrolled separation, and cascading not adversely impact the interconnection? (11) Thank you for the opportunity to comment.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst abstains and offers the following comments for consideration. 1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Failure to do so could result in a situational awareness issue (i.e. lack of accurate data and information) for the System Operator that could jeopardize system reliability. Additionally, and absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define its needs when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions cannot be performed]. R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator..." R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority." 2. Requirement R10, Part 10.1 and 10.2 – ReliabilityFirst believes the lead-in language in R10 ("…shall perform") does not read well with the two sub parts. ReliabilityFirst recommends the following for consideration in order to make the wording of the parent and sub parts read more clearly: a. 10.1 - Monitoring Facilities and the status of Special Protection Systems, within its Transmission Operator Area, and b. 10.2 - Obtaining and utilizing status, voltages, and flow data for Facilities and the status of Special Protection Systems, outside its Transmission Operator Area. 3. Requirement R12 – ReliabilityFirst requests clarification from the SDT for instances when a TOP identifies an IROL which is outside of the set of predefined identified IROLs, are the TOPs also required to not operate outside these unidentified IROLs per Requirement R12? 4. Requirement R14 – ReliabilityFirst believes the word "initiate" should be replaced with the word "execute". Because Operating Plans consist of "…a group of activities", we

would not want to only require the TOP to start (i.e., initiate) the first activity of the Operating Plan, but execute all activities that are part of the Operating Plan to mitigate the issue at hand.
Group
PacifiCorp
Sandra Shaffer
No
PacifiCorp does not favor approval of TOP-001-3 as drafted. PacifiCorp supports the comments of MidAmerica and objects for the following additional reasons: (1) The phrase “identified phase angle and equipment limitations” used in the proposed definition of Real-Time Assessment is vague, specifically the use of the term “identified.” Clarification would be needed since compliance with R13 requires a Real-Time Assessment every 30 minutes. (2) In addition, not all EMS systems can monitor phase angles using current online tools. This technology is not available in our system and we are not sure when it will be.
Individual
Texas Reliability Entity, Inc.
Texas Reliability Entity, Inc.
No
WRT to Requirement 10: Should Remedial Action Scheme be used instead? How will an entity support “as necessary”? How will a CEA accept “as necessary”? Transmission Operator Area ignores a Transmission Operator that DIRECTS ”the operations of the transmission facilities” and may cause a reliability gap in the Standard in this Interconnection. The VSLs are geared towards zero tolerance. Example- R8 appears to be a violation if one TOP is not informed. R10 High VSL is one item is not monitored (Is that one line?) The R8 VSL adding a component to the R8 Requirement that does not otherwise exist in R8. This VSL modification of the R8 Requirement weakens the Requirement’s beneficial effect on the reliability of the BES. In effect, the VSL modification negates the requirement in R8 by adding at the end ‘unless you can’t’. The added phrase in the VSL needs to be added in the R8 Requirement, where it can be properly considered as part of the Requirement, or removed from the VSL. R8 VSL has the phrase “when conditions did permit such communications” added to the description of the violations. This phrase does not exist in the Requirement. If the SDT wishes to change the meaning of the Requirement it should add that quoted phrase to the Requirement itself. R16 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed. Also change the two occurrences of “Balancing Authority” to “Transmission Operator”. R17 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed. The removal of the phrase "may be performed either a day ahead or as much as 12 months ahead” in the revised definition of Operational Planning Analysis may impact the Real-time reliability of the Reliability Coordinator Area. The issue is that the new definition only refers to next-day operations. There is a possible gap since a time frame for the evaluation of one day up to 12 months may not be considered by registered entities because of the removal of the subject language. This gap is compounded by the fact that the Time Horizons for most of the requirements are either Same Day or Real-Time.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
ERCOT respectfully submits the following comments: 1. Regarding Requirement R13, ERCOT requests clarification that Requirement R13 does not apply during time periods where entities lose telemetry or EMS (an abnormal or emergency condition). During such time periods, registered entities may not be able to perform a Real-Time Assessment within 30 minutes (per definition). The reliability standards contemplate and allow for emergency circumstances and emergency plans in

other Reliability Standards. To ensure consistency, the SDT should provide clarification regarding the applicability of this requirement by either: limiting applicability to normal operating conditions; providing a metric for percentage of availability that constitutes compliance, or revising the requirement to account for system issues as mentioned. 2. ERCOT reiterates concerns regarding use of the term “Operating Plan” in Requirement R14. Because the definition of “Operating Plan” states that it is a “document”, use of the term “Operating Plan” may be too restrictive to allow for necessary actions to be taken as contemplated in Requirement R14 as most actions taken occur per procedures or constraint management plans, but the universe of responsive actions cannot be easily documented in a single “document”. To ensure that system operators have the flexibility needed to take whatever actions they deem necessary to mitigate an SOL, ERCOT suggests removal of the term Operating Plan. 3. ERCOT respectfully submits that Requirements R1 and R2 are unnecessary because they are redundant with other requirements for a BA and TOP in Same-Day and Real Time Operations. ERCOT suggests deletion of Requirements R1 and R2.
Individual
Russell A. Noble
Cowlitz PUD
No
Cowlitz submits negative votes due to the SDT responses surrounding Real-Time Assessment (RTA) being performed at least every 30 minutes, and is concerned comment submitted by the stakeholders have not been adequately addressed. Cowlitz disagrees with the SDT responses which imply a full quality RTA can be performed in all circumstances. Comment submitted by Northeast Power Coordinating Council addressed a concern over the inability to perform RTAs during an EOP-008-1 primary to backup control center transition, and that responsible entities should be allowed a 2-hour window in which to reestablish a 30-minute RTA schedule. The SDT response stipulates that EOP-008-1 supports continuance of 30-minute RTAs during the transition. While Cowlitz agrees that the 30-minute RTA must continue, it will be limited to the available data from which to complete the assessment. Although EOP-008-1 allows for a 2-hour transition plan, it does not imply a 2-hour suspension of registered functional obligation is allowed; however, it does not require all systems to be maintained operational during the transition. The objective is to “ensure continued reliable operations of the Bulk Electric System” during an emergency; this of course is contingent upon circumstances not exceeding reasonable expectations of an entity’s ability to respond to emergency situations. The objective is to have a planned response to a contingency – loss of a control center – that will restore critical control and awareness tools necessary for continued functional obligations, not a guaranteed continuance of all the control and awareness tools. Cowlitz respectfully requests the SDT to clarify that the RTA must continue subject to the data available, and remove any misunderstanding concerning the derivation of the RTA when BES awareness has been compromised beyond the reach of the Reliability Standards.

Consideration of Comments

Project 2014-03 Revisions to TOP and IRO Standards

The Project 2014-03 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 35-day public comment period from December 3, 2014 through January 7, 2015. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from approximately 112 different people from approximately 78 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

- Made a grammatical correction to the rationale for Requirement R3 so that the second sentence now reads: "… due to its lack of knowledge of the system involved."
- Made a grammatical change to Measure M5 – "… issued by ~~the~~its Balancing Authority~~(s)~~ …".
- Made a grammatical change to Requirement R6 – "…issued by ~~that~~its Balancing Authority."
- Made a grammatical change to the rationale for Requirement R7 – "~~'~~This change~~s~~ is in response …".
- Added the term 'generation' to Requirement R11 for consistency with the Functional Model – "…maintain generation-Load-interchange balance …".
- Added clarifying language to the rationale for Requirement R13 - "The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation."

The SDT made clarifying changes for consistency to the VSLs for Requirements R6, R8, R11, R16, and R17 which can be found in the red-lined version of TOP-001-3.

The SDT also made several clarifying, non-substantive changes to the SOL Exceedance White Paper and the NOPR Issues document which can be found in the red-lined versions of those documents included with the next posting for this project.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities		1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10. Helen Lainis	Independent Electricity System Operator	NPCC	2
11. Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
12. Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13. Bruce Metruck	New York Power Authority	NPCC	6
14. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8
20. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21. Brian Shanahan	National Grid	NPCC	1
22. Wayne Sipperly	New York Power Authority	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Leo Staples	OG&E	SPP	5
2. Terri Pyle	OG&E	SPP	1
3. Don Hargrove	OG&E	SPP	3
4. Jerry Nottnagel	OG&E	SPP	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Connie Lowe	Dominion	X				X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Randi Heise	NERC Compliance Policy	NPCC	5
2. Louis Slade	NERC Compliance Policy	RFC	5, 6
3. Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Pawel Krupa	Seattle City Light	WECC	1
2. Dana Wheelock	Seattle City Light	WECC	3
3. Hao Li	Seattle City Light	WECC	4
4. Mike Haynes	Seattle City Light	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

5.	Dennis Sismaet	Seattle City Light	WECC	6

5.	Group	Greg Campoli	ISO RTO Council Standards Review Committee (SRC)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISO-NE	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Christina Bigelow	ERCOT	ERCOT	2
4.	Charles Yeung	SPP	SPP	2
5.	Terry Bilke	MISO	RFC	2
6.	Ali Miremadi	CAISO	WECC	2

6.	Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Edward Bedder	Orange and Rockland Utilities	NPCC	NA

7.	Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Shanahan	National Grid (Niagara Mohawk Power Corporation)	NPCC	1, 3

8.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hills			1
2.	Lee Schuster			3
3.	Dale Goodwine			5
4.	Greg Cecil			6

9.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

10.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utillities of Springfield	SPP	1, 4
2.	Kevin Foflygen	City Utilities of Springfield	SPP	1, 4
3.	Vinit Gupta	ITC Holdings	SPP	1

4.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
5.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
6.	Shannon Mickens	Southwest Power Pool	SPP	2
7.	James Nail	City of Independence, MO	SPP	3, 5
8.	Gary Slayton	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
9.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
10.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
11.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
11.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Anasis	Technical Operations	WECC	1
2.	Chris Higgins	Transmission Dispatch	WECC	1
3.	Fran Halpin	Duty Scheduling	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
12.	Group	Joe Depoorter	MRO- NERC Standards Review Forum										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
3.	Chuck Lawrence	American Transmission Company	MRO	1
4.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
5.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
9.	Ken Goldsmith	Alliant Energy	MRO	4
10.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
11.	Marie Knox	Midwest ISO Inc.	MRO	2
12.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
13.	Randi Nyholm	Minnesota Power	MRO	1, 5
14.	Scott Nickels	Rochester Public Utilties	MRO	4
15.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

17.	Tony Eddleman	Nebraska Public Power District		1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
2.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
3.	Ginger Mercier	Prairie Power, Inc.	SERC	3
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
5.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
6.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
9.	Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Sandra Shaffer	PacifiCorp						X				
N/A													
15.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
16.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
17.	Individual	Chris Scanlon	Exelon	X		X		X	X				
18.	Individual	Denise M. Lietz	Puget Sound Energy	X		X		X					
19.	Individual	Joshua Smith	Oncor Electric Delivery LLC	X									
20.	Individual	Scott Bos	Corn Belt Power Cooperative	X		X							
21.	Individual	David Jendras	Ameren	X		X		X	X				
22.	Individual	Catherine Wesley	PJM Interconnection		X								
23.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
24.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X									
25.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
26.	Individual	Gerald Farringer	Consumers Energy Company			X	X	X					
27.	Individual	Russ Schneider	Flathead Electric Cooperative			X	X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X		X							
29.	Individual	Donald E Nelson	Massachusetts Department of Public Utilities									X	
30.	Individual	Erika Doot	US Bureau of Reclamation	X				X					
31.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration, LP					X					
32.	Individual	Leonard Kula	Independent Electricity System Operator		X								
33.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
34.	Individual	Jason Snodgrass	Georgia Transmission Corp	X									
35.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
36.	Individual	Anthony Jablonski	ReliabilityFirst										X
37.	Individual	Texas Reliability Entity, Inc.	Texas Reliability Entity, Inc.										X
38.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
39.	Individual	Russell A. Noble	Cowlitz PUD			X	X	X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks the commenters for following the guidelines and will consider your supporting positions as part of its deliberations.

Organization	Agree	Supporting Comments of "Entity Name"
Exelon	Agree	Exelon will cast an Affirmative vote but agrees that the SDT should consider the comments filed by Duke Energy regarding:R1 be focused on the TOP issuing Operating Instructions and suggests the following revision to R1 for clarity: "Each Transmission Operator shall issue Operating Instructions, as necessary, to maintain the reliability of its Transmission Operator Area". R2 be focused on the BA issuing Operating Instructions and suggests the following revision to R2 for clarity: "Each Balancing Authority shall issue Operating Instructions, as necessary, to maintain the reliability of its Balancing Authority Area".
Corn Belt Power Cooperative	Agree	Support the comments submitted by the MRO NERC Standards Review Forum
Kansas City Power and Light	Agree	SPP - Robert Rhodes
Massachusetts Department of Public Utilities	Agree	NPCC

Organization	Agree	Supporting Comments of “Entity Name”
Lincoln Electric System	Agree	MRO NERC Standards Review Forum (NSRF)
Seattle City Light		NPCC
PacifiCorp		Berkshire Hathaway

1. **Do you agree with the changes made to respond to industry comments to proposed TOP-001-3? If not, please provide technical rationale for your disagreement along with suggested language changes**

Summary Consideration: The SDT has considered all of the comments submitted and has made the following clarifying, non-substantive changes due to industry comments

Rationale for Requirement R3: Added ‘to’ the second sentence to correct the grammar in the sentence. The sentence now reads: “…due to its lack of knowledge of the system involved.”

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by ~~the~~its Balancing Authority~~(s)~~ unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority’s Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by ~~that~~its Balancing Authority.

Rationale for Requirement R7: ‘This change~~s~~ is in response to the Independent Experts Review Panel (IERP) recommendations.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order- to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Rationale for Requirement R13: added – The Transmission Operator’s Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

The SDT made clarifying, non-substantive changes for consistency to the VSLs for Requirements R6, R8, R11, R16, and R17 which can be found in the red-lined version of TOP-001-3.

The SDT also made several clarifying, non-substantive changes to the SOL Exceedance White Paper and the NOPR Issues document which can be found in the red-lined versions of those documents included with the next posting for this project.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Regarding Requirement R13, there is concern that an operator will be obligated to perform the assessment. Given that the Rationale for Requirement R13, although not auditable, supports the Requirement's wording, suggest revising the Rationale Box to read: The new requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan may describe how to perform the Real-time Assessment. It would also be helpful to confirm that at times no actions may be required if system conditions have not changed within the thirty minute window and that previous contingency analysis or assessments may be used to perform the Real time Assessment for subsequent hours. A suggested revision to Requirement R13:R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes. And for Measure M13:M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment was performed at least once every 30 minutes, or in the timeframe specified in an Operating Plan when the Transmission Operator operates in a known state and is unable to perform the Real-time Assessment every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Organization	Yes or No	Question 1 Comment
		Appropriate wording consistent with this should be added to Section F. Associated Documents.

Response: The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:

1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.

2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.

Organization	Yes or No	Question 1 Comment
3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made. The SDT believes that with the additions made for clarification to the rationale for the requirement that no changes are required to the requirement wording. No change made. Since no changes were made to the requirement, no changes are required to the measure. No change made. The SDT believes that sufficient clarification has been provided in the rationale for the requirement and that no changes are required in Section F. No change made.		
Seattle City Light	No	Seattle City Light (SCL) appreciates the efforts made by the Standard Drafting Team to respond to comments from industry and create a quality Standard that is clear and complete. Considerable progress has been made from earlier postings. Some areas remain for improvement. Specifically, SCL disagrees with the R13 requirement for ensuring a real time assessment each 30 minutes, and believes a two-hour requirement to be sufficient and consistent with EOP-008. If 2 hours is too long, SCL urges consideration of a 60 minute requirement, as recommended in an earlier posting. A 30 minutes requirement in our opinion does not add enough reliability benefit to be worth the additional cost, effort, and compliance risk.

Organization	Yes or No	Question 1 Comment
		SCL also continues to recommend that R19 and R20 be deleted from TOP-001-3, as discussed previously. Finally, SCL is concerned with the growing number of BA-specific requirements (R11, R17, and R20) included a TOP-area Standard. While we understand the difficulty of aligning all requirements within the appropriate Standard area (BAL, TOP, etc.), we urge extra effort be made to maintain and promote such alignment more than has been done to date. For example, INT-009-2 included BA requirements that do not properly belong in that Standard but were included out of expedience and a lack of willingness to develop an appropriate new SAR. SCL recommends reconsidering the need to include BA-only requirements within a TOP-family Standard, and alternative approaches to addressing these reliability needs in a different Standard.

Response: The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:

1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.

2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where

Organization	Yes or No	Question 1 Comment

normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.

3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.

No change made.

As has been previously stated by the SDT, Requirements R19 and R20 serve to complete the loop on data exchange. Proposed TOP-003-3 sets out the requirements for the data itself but there needs to be corresponding requirements concerning the hardware and systems that allow for the data exchange to actually take place. The Commission has made it clear in past Orders that one can't assume that systems are in place when writing requirements for specific actions. In this case, that would mean that one can't assume that hardware or systems are in place to allow for data exchange simply because requirements exist that describe what data needs to be exchanged. No change made.

As a general concept, the SDT agrees that requirements pertinent to Balancing Authorities should reside in standards specific to Balancing Authorities. However, the existing, approved TOP standards already had several requirements applicable to Balancing Authorities and the SDT is obligated to maintain those requirements so as not to introduce a reliability gap. The scope of the SAR for

Organization	Yes or No	Question 1 Comment
Project 2014-03 did not allow for the SDT to revise the BAL standards where these requirements would most likely be placed so the SDT was obligated to retain the requirements within the TOP standards. The SDT did discuss this issue with NERC management and obtained an assurance that an overarching project to address the issue would be instituted in the future. No change made.		
ISO RTO Council Standards Review Committee (SRC)	No	Requirement R11, as proposed, states, “Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.” The SRC suggests that Requirement R11 is duplicative of requirements and obligations placed on Balancing Authorities in the BAL Standards and, therefore, suggests deletion of Requirement R11.
Response: The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can’t assume something based on other requirements that dictate certain actions. In this case, just because an entity has to adhere to requirements for AGC or DCS and that it can’t do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made.		
Con Edison, Inc. National Grid	No	Requirement R13 is problematic. The 30 minute requirement in R13 is too restrictive and inconsistent with EOP-008, which allows two hours to restore such functionality. If entities are permitted two hours to restore situational awareness following an evacuation, entities should be granted the same time consideration to restore real-time assessment capability in R13. Therefore we recommend either of the following revisions to R13: o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every two hours. o Each Transmission Operator shall maintain that a Real-time Assessment is performed at least once every 30 minutes when the EMS & SCADA are functional. Following the loss of EMS, a Transmission Operator shall regain ability to perform real-time assessments within two hours.

Organization	Yes or No	Question 1 Comment
Cowlitz PUD	No	Cowlitz submits negative votes due to the SDT responses surrounding Real-Time Assessment (RTA) being performed at least every 30 minutes, and is concerned comment submitted by the stakeholders have not been adequately addressed. Cowlitz disagrees with the SDT responses which imply a full quality RTA can be performed in all circumstances. Comment submitted by Northeast Power Coordinating Council addressed a concern over the inability to perform RTAs during an EOP-008-1 primary to backup control center transition, and that responsible entities should be allowed a 2-hour window in which to reestablish a 30-minute RTA schedule. The SDT response stipulates that EOP-008-1 supports continuance of 30-minute RTAs during the transition. While Cowlitz agrees that the 30-minute RTA must continue, it will be limited to the available data from which to complete the assessment. Although EOP-008-1 allows for a 2-hour transition plan, it does not imply a 2-hour suspension of registered functional obligation is allowed; however, it does not require all systems to be maintained operational during the transition. The objective is to “ensure continued reliable operations of the Bulk Electric System” during an emergency; this of course is contingent upon circumstances not exceeding reasonable expectations of an entity’s ability to respond to emergency situations. The objective is to have a planned response to a contingency - loss of a control center - that will restore critical control and awareness tools necessary for continued functional obligations, not a guaranteed continuance of all the control and awareness tools. Cowlitz respectfully requests the SDT to clarify that the RTA must continue subject to the data available, and remove any misunderstanding concerning the derivation of the RTA when BES awareness has been compromised beyond the reach of the Reliability Standards.
Response: The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable,		

Organization	Yes or No	Question 1 Comment
and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement: 1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim. 2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement. 3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the		

Organization	Yes or No	Question 1 Comment
29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made.		
Duke Energy	No	R1&R2: Duke Energy still has concerns regarding the wording associated with R1 and R2. The SDT stated in their consideration of Duke Energy comments that, "Specific actions for specific situations will be covered under the applicable standards." Our fear is that the language opcan still be viewed as a failure to act or a failure to maintain. Duke Energy understands and agrees, through informal discussions with the SDT that the intent of R1 and R2 is that the BA and TOP must take some action in order to maintain the reliability of the BES and not whether the BA or TOP succeeded in said action. R9: Duke Energy agrees with the removal of "sustained" and the addition of a timing requirement for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. However, would like the SDT to provide a response to the following question, If the primary channel (RTU, etc.) is out of service and the backup is working properly, then is the expectation for the BA and TOP to notify the RC and other entities affected that the primary communication channel is out service? (Even though monitoring, assessment capabilities, etc. have not been affected). Duke Energy understands and agrees, through informal discussions with the SDT, that if back-up communication channels from the BA and TOP are still providing data then there is no need for communications to the RC and others affected as described in R9. Associated Documents (SOL Exceedance document): Duke Energy requests clarification on the compliance ramifications of the Associated Documents

Organization	Yes or No	Question 1 Comment
		section. Upon our review of Appendix 3A of the NERC Rules of Procedure, Associated Documents are not included in the Appendix, and thus an entity would not consider the section to be an enforceable part of the standard for compliance purposes. We do not feel that including a URL, rather than attaching the entire document to the standard clears up any confusion the industry may have on this issue. Duke Energy maintains that this document could be viewed as an expansion of what is currently considered to be an SOL, and feels that this document should be viewed as purely a Guideline/Technical Basis document as is currently labeled in other NERC standards (see CIP-004-7).
Response: The SDT agrees with the stated intent of the requirements offered by the commenter, specifically the intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made. The SDT agrees with the interpretation provided by the commenter, specifically that if back-up communication channels from the Balancing Authority and Transmission Operator are still providing data then there is no need for communications to the Reliability Coordinator and others affected as described in Requirement R9. Such an interpretation is consistent with similar requirements on notification of facility outages in other standards. No change made. The SDT agrees that the SOL Exceedance White Paper is a guideline technical document providing clarification on how to determine an SOL and what needs to be done upon determining an SOL. For clarification, the SDT has revised the wording with reference to the White Paper in Section F. See redlined version for exact text.		
Colorado Springs Utilities	No	Thank you standard drafting teammates for all of your work on this complex standard! R13 Comment: R13 requires that a Real-time Assessment is performed at least once every 30 minutes. We believe that this is in conflict with EOP-008 which allows for a two hour transition period to back-up control center. How does the standard drafting team anticipate that an entity that is failing

Organization	Yes or No	Question 1 Comment
		over to a back-up control center is to maintain compliance with this requirement? This requirement needs to be modified to make sure it is consistent with EOP-008. General Comment: We re-submit our comment concerning the use of the word "maintain" which has much the same implications as "ensure". We concur that entities must act timely and prudently for the reliability of the BES, but entities should not be unduly held accountable for system conditions outside their control that lead to reliability issues of the BES. We favor the word "address" and "address reliability" to "maintain" and "maintain reliability." The fact that a reliability issue or even a black-out has occurred is not sufficient to prove that entities were not appropriately acting. We must avoid requirement language that attaches liability just because a reliability event occurs.

Response: The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:

1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.

2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where

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normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement. 3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made. The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and sees no reason to revise the current wording. The SDT moved from 'ensure' to 'maintain' at the express request of numerous entities in previous postings. The SDT agrees that simply because bad things happened it does not mean that an entity did not do its duty or necessarily acted improperly. No change made.		
SPP Standards Review Group Oklahoma Gas & Electric	No	TOP-001-3R1 & R2 - We take exception to the step back which the SDT has taken with the change of 'address' to 'maintain' in Requirements R1 and R2. The SDT mentioned that one of the reasons for this change was to eliminate

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		the threat of double jeopardy. We don't see that happening with the terminology being proposed. Rationale Box for R3 - In the Rationale Box for Requirement R3, insert a 'to' between 'due' and 'its' in the last line. R5 - Change 'Balancing Authority' to 'Balancing Authority(s)' in the second line of Requirement R5 to make the requirement consistent with the measure. R6 - Change 'that' in the 3rd line to 'its' for consistency with Requirement R4. Rationale Box for R7 - In the Rationale Box for Requirement R7, delete the apostrophe in front of 'This' at the start of the 2nd sentence and also change 'changes' to 'change' in the same sentence. R9 - If the SDT's intent was for the 30-minute threshold to apply to both planned and unplanned outages, then the commas surrounding the phrase 'and unplanned outages of 30 minutes or more' need to be deleted. As written, the 30-minute threshold only applies to unplanned outages. If this wasn't the SDT's intent, it should be. Additionally, the current wording obligates the Balancing Authority and Transmission Operator to notify its Reliability Coordinator whenever an RTU goes down. We should focus on outages of equipment which have an impact on the reliability of the Interconnection. Therefore, we recommend the following language: 'Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned and unplanned outages of 30 minutes or more for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, which adversely impact the reliability of the Interconnection.'

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		R10 - We have concerns about the elimination of the caveat regarding identification of facilities by the Transmission Operator for inclusion in the determination of SOL exceedances. Leaning on the 'as necessary' in Requirement R10 is too much of a stretch. We suggest the SDT re-insert the 'identified by the Transmission Operator' in R10 as follows: 'Each Transmission Operator shall perform the following as necessary, when identified by the Transmission Operator, for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:' Change 'voltages' in Requirement 10, Part 10.2 to 'voltage'. Make the same change in the Measure. R11 - Change 'Load-interchange balance' to 'generation-Load-interchange balance' which is consistent with the definition of Balancing Authority as contained in the Functional Model. That definition also includes a component for contributing to Interconnection frequency which the SDT has already incorporated in Requirement R11. VSLs for R8 - If the SDT has not changed its position on the inclusion of 'other' in this requirement, usage by the way which is consistent with that in Requirement R7, then 'other' needs to be deleted from the Lower, Moderate and High VSLs for Requirement R8. VSLs for R16 and R17 - Measures 16 and 17 have been inserted in the Severe VSLs for Requirements 16 and 17, respectively. They should be deleted. We recommend that all changes we have proposed for the standards be reflected in the VSLs and RSAW as well. Implementation Plan Split the 2nd paragraph on the 4th page into two sentences. Do this by replacing '...SW Outage Report, and this implementation plan...' with '...SW Outage Report. This implementation

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		plan…' at the end of the 3rd and the beginning of the 4th lines of the paragraph. In the paragraph under General Considerations on page 4, delete the 's' on 'Requirements R5' at the end of the 3rd line. In the 1st paragraph under Implementation Plan for Definitions on page 8, replace 'definitions' in the 4th line with 'definition.' SOL Whitepaper The '3.' at the top of page 3 should be '4.'. Split the 1st sentence of the paragraph immediately following '4.' above into two sentences by making the following change in the 3rd line of that paragraph. Replace '...Requirement R2 sub-requirements, the assumption being that...' with '...Requirement R2 sub-requirements. The assumption being that...'. In the last line under the first 3 on page 4, change 'limit' to 'limits'. Replace 'Owner' at the top of page 6 with 'Owner's'. Capitalize 'process' at the end of the last line of the Operating Process definition on page 10. NOPR Issues The language quoted on page 2 for IRO-008-2, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 2 for IRO-008-2, Requirement R4 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 3 for IRO-002-4, Requirement R2 is not consistent with the language posted in the final ballot package of October 10, 2014.

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		The language quoted on page 7 for TOP-001-3, Requirement R11 is not consistent with the language currently posted for comment and ballot. The language quoted on page 7 for TOP-001-3, Requirement R13 is not consistent with the language currently posted for comment and ballot. The language shown is actually Requirement R11 of the posted version. The reference to proposed IRO-014-2, Requirement R1 on page 20 should actually be to IRO-014-3. Part 1.1 of IRO-017-1, Requirement R1 shown on page 20 is missing the 1.1 designation. The language quoted on page 21 for TOP-003-3, Requirement R5, Part 5.3 is not consistent with the language posted in the final ballot package of October 10, 2014. The language quoted on page 21 for IRO-010-2, Requirement R3, Part 3.3 is not consistent with the language posted in the final ballot package of October 10, 2014.

Response: R1 **-** The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.

R3 - The SDT agrees and has made the suggested non-substantive clarifying change. See summary consideration for actual wording.

R5 - The SDT agrees that there is an inconsistency but believes the proper fix is to adjust the measure to be consistent with the requirement. The SDT has made the suggested non-substantive clarifying change. See summary consideration for actual wording.

R6 - The SDT agrees and has made the suggested non-substantive clarifying change. See summary consideration for actual wording.

R7 - The SDT agrees and has made the non-substantive semantic change as suggested. See summary consideration for actual wording.

R9 - The 30-minute threshold only applies to unplanned outages. All impactful planned outages require notification. However, the SDT does not agree that such verbal notifications necessarily go down to the RTU level. The SDT believes that ICCP quality code

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information is an acceptable form of communication and is included within the measure as "electronic communication". Additionally, reporting requirements can also be covered as part of Operating Plans between the Transmission Operator and Reliability Coordinator. The intent of the standard is not to be administrative in nature. Allowing entities to determine what is significant would lead to an inconsistent application of the requirement. No change made. R10 – The SDT believes the current wording is correct and finds the suggested re-insertion redundant. No change made. R10.2 – The SDT believes the current wording is correct and believes the use of the plural term is correct in this context. No change made. R11 – The SDT agrees that the suggested change is in keeping with the language in the Functional Model which is what the SDT was trying to do. The SDT has made the non-substantive change. See summary consideration for actual wording. Corresponding changes were made to the measure and VSLs. VSL for R8 – The SDT has not changed its position with regard to the use of 'other' and has deleted the term from the VSLs as suggested. See red-lined standard for change. VSLs for R16/R17 – The SDT agrees and has made the suggested change. See red-lined standard for change. The SDT has updated the VSL language as needed. The SDT does not have the authority to update RSAW language but it will pass on the needed changes to NERC Compliance. The Implementation Plan for Project 2014-03 has already been adopted by the Board and the SDT is unable to make semantic changes to the document at this time. The document was posted with proposed TOP-001-3 solely for convenience of reference. No change made. SOL Exceedance White Paper – The SDT agrees and has changed the numeric value to 4. See red-lined White Paper for change. The SDT believes that splitting the sentences would slightly change the intent of the paragraph without adding any additional clarity. No change made. The SDT agrees and has made the suggested change. See the red-lined White Paper for change. The SDT agrees and has made the suggested change. See the red-lined White Paper for change. The SDT agrees and has made the suggested change. See the red-lined White Paper for change.		

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NOPR Issues: The SDT agrees on the discrepancy for proposed IRO-00-8-2, Requirement R2 and has corrected this problem in the document. Proposed IRO-008-2, Requirement R4 should not have been listed as a pertinent requirement. The text prior to the list of pertinent requirements was corrected to show the correct list of requirements. The proper reference on page 3 is to proposed IRO-002-4, Requirement R3. The text for proposed TOP-001-3, Requirement R11 has been updated on page 7. The text for proposed TOP-001-3, Requirement R13 has been updated on page 7. The reference to proposed IRO-014-3 on page 20 has been corrected. The 1.1 designation has been added to proposed IRO-017-1 on page 20. The text of proposed TOP-003-3, Requirement R5, Part 5.3 and IRO-010-2, Requirement R5, Part 5.3 has been updated on page 21.		
Bonneville Power Administration	No	BPA's primary concern is with the way Requirement R8 is written. It requires BPA to inform the RC and any impacted TOP's and BA's of an actual or expected operating condition that results in or could result in an Emergency. Emergency is defined in the NERC Glossary as: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" BPA could interpret this to mean that our dispatchers should call the RC anytime any 115kV line anywhere on BPA's system is threatened by fire, wind, ice, or other conditions. BPA is also concerned about having to inform these other parties of "expected operating conditions ...that could result in an Emergency." It is not clear to BPA how an auditor will interpret this. BPA is concerned that, given how broad the definition of "Emergency" is, we might violate R8 for not anticipating a particular operating condition or its full consequences. Again, "Emergency" does not merely refer to a WECC-wide stability event like September 8. This is written such that it includes a simple trip of a 115kV line.
Response: The SDT believes that the requirement is written correctly and captures the intent of the SDT in this matter. Other entities need to know what is happening in other areas that will impact the reliability of the BES in order to properly manage its own systems. If the loss of a 115 kV line impacts BES reliability, the outage needs to be shared with other entities. Using 'Emergency' as a qualifier for these notifications provides a limit to the number of notifications that will be required. No change made.		

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MRO- NERC Standards Review Forum	No	: The NSRF cannot support R1 and R2 as written within the proposed TOP-001-3. The NSRF believes that as written, these Requirements are a catch all, ambiguous, and not measurable. FERC Order 693, section 253 states, "...compliance will in all cases be measured be determining whether the party met or failed to meet the Requirement...." The NSRF does not understand what is being required by the TOP and BA, respectfully. Granted, the SDT wants a TOP and BA to "maintain the reliability of its Area via its own actions or by issuing Operating Instructions". The NSRF views this as what a TOP and BA should be doing at all times. But in order for a TOP or BA to show proof of compliance, the industry needs to know what is required of them? The SDT has not provided any relief to the TOP and BA as we move into risk based compliance activities. The NSRF has referred to the Standards Process Manual to point out to the SDT that Standards Process Manual section 2.4 describes a "Results Based Requirement" as "Each requirement of a reliability standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective and not how that objective is achieved". In FERC's Order regarding NERC's Five-Year Performance Assessment [149 FERC Â¶ 61,141, P 70 (2014)], the Commission recently highlighted the importance of improving consistency: "The Commission recognizes and supports NERC's efforts to increase consistency and promote coordination across the ERO Enterprise. A key element of consistency is the transparency of the ERO Enterprise's processes and its outcomes. Improved consistency and coordination helps to clarify the roles and responsibilities of NERC and the Regional Entities and should lead to more efficient and uniform work practices. Specifically, we believe that a focus on achieving consistent compliance and enforcement outcomes (e.g., monetary penalties, registration decisions, and consistent understanding of Reliability Standard requirements) while not equating consistency with a "lowest common denominator" approach would provide the greatest benefit to registered

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		entities." As written, R1 and R2 do not provide a "consistent understanding of Reliability Standard requirements". The NSRF has even given proposed rewrite of "A possible rewrite of R1 and R2 to read: "Each (BA, TOP) shall issue Operating Instructions to address the reliability of its area when direct actions require more assistance ". The SDT replied that "The SDT does not believe that Requirements R1 and R2 are problematic. The requirement simply states that an entity maintain the reliability of its area by the means it has at its disposal either through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement". The NSRF does not agree with the "spirit" that the SDT believes is the intent of the Requirements. If the SDT believes that the "TOP and BA shall maintain the reliability of its area by the means it has at its disposal", then that should be clearly stated within R1 and R2. The NSRF believes that section 253 of FERC Order 693 could then be adhered, too. The NSRF recommends that the SDT consider removing the following language from the proposed "Real-time Assessment" definition: "known Protection System and Special Protection System status or degradation," The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a Protection System failures. EMS systems using real-time contingency

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		analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13.What happens when the analysis cannot be accomplished within 30 minutes due to other emergency conditions? Whereby the Entity is reacting to a priority situation? With regard to R13, we believe the SDT has improved the language by revisions such that the TOP shall “ensure that a Real-time Assessment is performed at least once every 30 minutes;” however, we continue to question the 30-minute requirement and believe that there will be tremendous difficulty in achieving this without defect. Rather, we would recommend the following language: R13: “Each TOP shall ensure that a Real-time Assessment is performed with such periodicity so as to ensure continuous situational awareness of the TOP.” Measure M13 would need commensurate edits to conform to this R13 language. Entities have made these comments before and the SDT did not agree as they said; The SDT does not agree. The requirement allows for an entity to arrange for another entity to perform the assessment which aligns with requirements in approved EOP-008-1. Approved EOP-008-1 specifically requires entities to have tools and applications to ensure that System Operators have situational awareness of the BES. It goes on to require that entities take necessary actions to manage the risk to the BES during periods when primary or backup functionality may not be available. This requirement isn’t about maintaining RTCA or any other specific tool, it’s about maintaining situational awareness at all times. No change made. The first concern is the NSRF believes that without further clarification, System Operators will not have the “situational awareness” because they will not know “known

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		Protection System and Special Protection System status or degradation...” per the Real-time Assessment definition, thus will most likely be non-compliant on a daily basis. A 4000 breaker Transmission system can have up to 20,000 (4000 x 5 parts of a Protection System) parts that would need to be tracked every 30 minutes. This is unrealistic and not physically possible. The SDT continues to use the words “have situational awareness” in their response to comments, and that the Requirement is not about an RTCA. But without using the RTCA, how will the System Operator prevent instability, uncontrolled separation or Cascading outages, per the Purpose of this proposed Standard? The Real-time assessment must consist of existing and potential operating conditions, per the definition. A System Operator cannot calculate all the minimum inputs every 30 minutes without using some type of calculating device. The NSRF would also wish to point out that the SDT may believe that an Entity’s RTCA may run every several minutes and thus fulfilling the 30 minute requirement. An Entity cannot be directed to have an RTCA and most RTCA systems, do not function properly if all the data points are not provided, i.e., transmission lines out of service due to severe weather, thus unable to provide the required “situational awareness”.

Response: The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made.

The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time.

The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity’s obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to

Organization	Yes or No	Question 1 Comment
the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement: 1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim. 2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement. 3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue.		

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No change made.		
ACES Standards Collaborators	No	(1) Requirements R1 and R2 are vague, overly broad, and duplicative of other requirements and will be difficult to demonstrate compliance with and as a result may distract System Operators from their reliability mission. If there is a disturbance on the transmission system, there could be a potential violation of R1 and R2 because the TOP/BA did not “maintain reliability” of its area regardless whether is actions were appropriate or not. This requirement is very subjective and will allow auditors or investigators to interpret a system operator’s actions after-the-fact to determine if they acted appropriately. There is nothing in these requirements that allow for a reasonable measure of performance. The Compliance Enforcement Authority will evaluate whether actions were taken, Operating Instructions were issued, and whether or not reliability was maintained. There could be a violation whenever a disturbance occurs in the TOP/BA area including events beyond their control such as tornadoes or hurricanes, as reliability was not maintained. These requirements are duplicative with many other requirements. For example, failing to initiate an Operating Plan to mitigate an SOL exceedance in R14 is failing to take action or issue Operating Instructions to maintain reliability. While the RSAW’s do attempt to limit the burden of proving compliance with every Operating Instruction by instructing auditors to monitor compliance during events, RSAWs are simply guidance documents that an auditor is not obligated to follow. Thus, a TOP and BA must be able to prove compliance by retaining every Operating Instruction and that it acted in response to every operating threat. This is a tall order that will distract System Operators from their reliability mission and as a result be a detriment to reliability. While System Operators are already tasked with logging actions and information throughout the day, their standards for documenting information likely are not at a level that would be auditably compliant. Thus, System Operators will have to focus time and energy that should be focused on Operating the

Organization	Yes or No	Question 1 Comment
		system with writing auditably compliant logs. A better solution would be to revert these requirements back to the authority requirements of the existing standards. The data retention section of this standard exacerbates the issue by requiring evidence that is not an operator log or voice recording to be retained for up to two calendar years. What other evidence does the drafting team foresee will be used to demonstrate compliance? These requirements need to be revised to include a reasonable measure of performance and the VSL table should be modified to account for instances where contributing factors led to reliability not being maintained. (2) Requirements R1 and R2 do not line up with the functional model. A TOP is obligated per R1 “to act to maintain the reliability of its Transmission Operator Areas via its own actions or by issuing Operating Instructions.” This means that a TOP must respond to all reliability threats including those that are not its responsibility. Consider a large generating plant trips and frequency declines significantly but there are not SOL or IROL violations or voltage violations. In other words, the transmission system is within operating limits with the exception of frequency. The TOP should not act because the BA should be acting to recover frequency. In fact, if the TOP does act, it likely will be detrimental to reliability. However, the TOP would be in technical violation of the requirement because it did not act and or issue Operating Instructions in response to a reliability threat within its Transmission Operator Area. (3) Requirements R3, R4, R5, and R6 should be modified in several ways. First, we disagree with the classifications of High VRF and Severe VSL for failing to comply with an Operating Instruction in all instances. Failing to follow an Operating Instruction during routine operations, is unlikely “to directly cause or contribute to Bulk-Power System instability, separation or a cascading sequence of failures” as required by a High VRF. As an example, the failure to implement the Operating Instruction correctly in the Arizona-Southern California did not directly cause the outage as it was not a root

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		cause. Rather it was the initiating action and other standards violations were required to cause the blackout. The VRF should be reduced to Medium. Second, the VSL table should be graduated to allow for instances of both Operating Instructions issued during Emergencies and Operating Instructions issued during non-Emergencies. Finally, the requirements should be modified to take into account Emergency and non-Emergency conditions. Failing to implement an Operating Instruction during a non-Emergency does not pose the same risk to BES reliability as failing to implement an Operating Instruction during an Emergency. Failing to implement an Operating Instruction during a non-Emergency would require other standards violations to cause a blackout. Under the current draft, all failures to comply with Operating Instructions could result in fine of $1 Million per day, per violation. This does not seem reasonable, especially in the instance of a small generator or Distribution Provider that would have limited impact on reliability from failing to implement varying types of Operating Instructions. (4) Requirement R7 has reverted back to comparable Emergency procedures, which the drafting team has acknowledged in the rationale box of the previous posting as “impossible to measure.” Has the drafting team determined a way to measure and if so has it been documented? (5) Requirement R8 should be limited to known impacted Balancing Authorities and known impacted Transmission Operators “within the RC Area.” This modification would be consistent with R7. As currently written, R8 requires a TOP to inform all other BAs and TOPs in the Interconnection, as they would be impacted entities. Further, the percentages in the VSL do not accurately reflect the amount of entities that would need to communicate. The metric of 15 percent or less of the impacted TOPs assumes that 10 or more entities should be notified. In an Emergency, the RC and neighboring entities should be notified, as system operators should

Organization	Yes or No	Question 1 Comment
		be focused at mitigating the conditions leading to the Emergency. The RC is responsible for wide-area reliability. (6) Requirement R9's VSL table needs to be modified. As written, a Severe VSL will result if a BA/TOP does not contact four or more known impacted interconnected entities. The requirement does not state how many entities must be contacted. If the BA/TOP contacts its RC, the burden should shift to the RC to coordinate with other impacted entities. The requirement needs to be clarified and VSL table should be modified. (7) Requirement R10 has improved with the removal of non-BES facilities. (8) Requirement R11 is duplicative with many of the NERC BAL standards. A BA is expected, as required by these BAL standards, to monitor the load-interchange balance and frequency its own area to calculate ACE as part of its efforts to maintain compliance with CPS1, CPS2, DCS, and eventually with the Balancing Authority ACE Limit, defined within NERC Standards BAL-001-2, and currently on file with FERC. Moreover, several other BAL requirements identify criteria that a BA must use to properly calculate its ACE and identify the need for redundant mechanisms to monitor the ACE components. (9) Requirement R15 is duplicative with R8. Both requirements address the TOP notifying the RC of actual operations that could result in an Emergency. Actions taken to return the system to within limits when a SOL has been exceeded could fall into this category. R15 should be struck. (10) The purpose statement is vague and overly broad and should be revised. The purpose of the Energy Policy Act of 2005 is to ensure reliability operation which by definition includes preventing instability, cascading, and uncontrolled separation. Thus, this is the purpose of the reliability standards as a whole. Furthermore, the way the purpose statement is written implies that instability, uncontrolled separation, and cascading may

Organization	Yes or No	Question 1 Comment
		not adversely impact the interconnection with the "that adversely impact the reliability of the Interconnection." How would instability, uncontrolled separation, and cascading not adversely impact the interconnection? (11) Thank you for the opportunity to comment.

Response: (1) The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. As to data retention, the SDT points out that there are additional items cited in the measure that could be employed. No change made.

(2) The Transmission Operator would certainly not sit by idly while frequency was declining. At the least, it would be expected to be in communication with the Balancing Authority and such communications may lead to the issuance of Operating Instructions. The requirement simply states that an entity maintain the reliability of its area through its own actions or by issuing Operating Instructions. If the entity does that, then the SDT believes it has met the spirit and intent of the requirement. No change made.

(3) The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should not attempt such differentiation. This would carry over to the VSLs as well. And it lends credence to the assignment of a High VRF. In addition, the approved TOP-001-1 has similar requirements with a High VRF. The SDT is obligated to maintain this VRF unless sufficient technical rationale can be provided to justify a change. To date, no one has provided such rationale. No change made.

(4) The SDT added 'comparable' to the requirement language at the request of numerous entities in the previous posting. In its explanation for that change, the SDT expressed the belief that comparability would be sorted out after the fact. The important issue is to respond to the Emergency. No change made.

(5) The SDT believes that the requirement language does not necessitate notification to all Balancing Authorities and Transmission Operators within the Interconnection as not all will be impacted by actions far from the source. No change made.

(6) The SDT believes the current language is correct. The Reliability Coordinator should not arbitrarily be assigned the task of notifying other entities. The SDT believes that this is properly the role of the original Transmission Operator or balancing Authority. As for the VSL, the entity should know how many other entities are impacted and need to be notified which will allow for the VSL to be properly measured. No change made.

Organization	Yes or No	Question 1 Comment
(7) Thank you for your support. (8) The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can't assume something based on other requirements that dictate certain actions. In this case, just because an entity has to adhere to requirements for AGC or DCS and that it can't do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made. (9) The SDT believes that the two requirements are not duplicative. The conditions are decidedly different. Requirement R8 is referring to situations and notification for actions that cause, or could cause, an Emergency. Requirement R15 is referring to actions that were taken to relieve SOL exceedances. No change made. (10) The SDT believes that the Purpose Statement describes the intent of the accompanying standard. No change made.		
PacifiCorp	No	PacifiCorp does not favor approval of TOP-001-3 as drafted. PacifiCorp supports the comments of MidAmerica and objects for the following additional reasons: (1) The phrase "identified phase angle and equipment limitations" used in the proposed definition of Real-Time Assessment is vague, specifically the use of the term "identified." Clarification would be needed since compliance with R13 requires a Real-Time Assessment every 30 minutes. (2) In addition, not all EMS systems can monitor phase angles using current online tools. This technology is not available in our system and we are not sure when it will be.
Response: The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time. When crafting the definition, the SDT purposely included the term 'applicable' in front of all the listed items as a qualifier that would catch the situation described in the comment. If an entity doesn't have phase angle restrictions then that information is not applicable or identified. No change made.		
Liberty Electric Power LLC	No	The Operating Instruction should be identified as such by the issuing entity. Not identifying an Operating Instruction will lead to confusion over whether the instruction is a Marketing Instruction or an Operating Instruction. For example, a unit being released from the grid can self-dispatch if the release

Organization	Yes or No	Question 1 Comment
		is for economics. But if the release is considered an Operating Instruction due to conditions of which the GOP is not aware, a violation could occur. Suggest adding one word - Identified - to R3 prior to the term Operating Instruction.
Response: The protocol for issuing Operating Instructions is beyond the scope of this project. However, if the protocol is followed, it is clearly evident when an Operating Instruction is issued. No change made.		
American Electric Power	No	R9: AEP disagrees with requiring notification of every planned and unplanned outage of 30 minutes or more, especially since the requirement could be interpreted as applying to the individual RTU's themselves, and irrespective of their impact to the reliability of the BES. AEP believes the proposed language is overly prescriptive, does not accomplish the desired results of the SDT, and provides no benefit to the reliability of the BES. BAs and TOPs should be interested in knowing that they have quality data coming in, i.e., knowing whether or not the data is valid. There is no reliability benefit in requiring notification of every outage of every piece of equipment producing that data. PJM, for example, is in no position to know or determine how or if an individual RTU impacts reliability, or even the quality of the solution of a State Estimator. AEP believes it is far more important to know the *quality* of data feeding the applicable systems (for example, a state estimator), rather than the status of each piece of equipment in the systems which provide that data. AEP requests the drafting team articulate what reliability benefit they believe is gained by providing the status of individual pieces of equipment within R9.The phrase "all planned outages, and unplanned outages of 30 minutes or more" could have multiple interpretations. One possible interpretation is that the 30 minute threshold only applies to an unplanned outage, thereby inferring that notification be made for each and every planned outage, regardless of its duration. Another possible interpretation is that the 30 minute threshold

Organization	Yes or No	Question 1 Comment
		is used for both planned *and* unplanned outages. Please clarify this phrase to make it clear which outages the 30 minute threshold applies to. The text “between the affected entities” seems to imply inter-connections, even though it does not read as such earlier in R9 (known impacted interconnected entities).AEP recommends changing the language “all planned outages, and unplanned sustained outages” to simply say “all significant outages” and allow the TO and TOP to determine what is significant to the reliable operation of the BES.AEP voted affirmative on draft 3, a draft we consider superior in content to the draft currently proposed. AEP has chosen to vote negative on draft 4, driven by our objections to the latest revisions to R9, as expressed above.
Response: The 30-minute threshold only applies to unplanned outages. All impactful planned outages require notification. However, the SDT does not agree that such verbal notifications necessarily go down to the RTU level. The SDT believes that ICCP quality code information is an acceptable form of communication and is included within the measure as “electronic communication”. Additionally, reporting requirements can also be covered as part of Operating Plans between the Transmission Operator and Reliability Coordinator. The intent of the standard is not to be administrative in nature. To use the provided example, if an entity is still going to receive valid data despite the loss of an RTU then that entity hasn’t been impacted by the outage and wouldn’t need to be verbally notified. Allowing entities to determine what is significant would lead to an inconsistent application of the requirement. No change made.		
Puget Sound Energy	No	The use of the word "maintain" instead of "address" raises the same issues as the word "ensure" in the previous drafts of this standard - if a reliability issue arises, an enforcement entity might find a violation of requirements R1 and R2 simply because an entity failed to "maintain the reliability" of its area (whether or not the entity’s operators took appropriate action to respond to the issue). In addition, the current draft does not address the burden associated with the need to demonstrate compliance with each Operating Instruction under requirement R3. I have previously commented on this issue and I continue

Organization	Yes or No	Question 1 Comment
		to believe that the approach taken to Operating Instructions under the COM-002 standard more appropriately balances compliance burden with reliability needs.
Response: The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and having agreed sees no reason to revise the current wording. No change made. The SDT believes that it has addressed the burden associated with demonstrating compliance through the measure, data retention, and associated RSAW language regarding this issue. No change made.		
Oncor Electric Delivery LLC	No	Proposed Standard TOP-001-3 R9 States: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. In response to R9, Oncor recommends for the requirement to make it mandatory for BAs and TOPs to notify only negatively impacted interconnected TOs, TOPs and GOPs. Oncor does not feel it necessary to notify registered entities that do not have reliability control functions to the BES. Oncor's suggested rewording for R9: R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected TOs, TOPs and GOPs of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. Proposed Standard TOP-001-3 R10 States:R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] 10.1. Within its

Organization	Yes or No	Question 1 Comment
		Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. ERCOT region is structured to support a deregulated market in which ERCOT monitors facilities for all TOPS and has a centralized view of the entire region to maintain reliability. TOPs operating within ERCOT currently do not have the technical capability to monitor facilities of neighboring TOPs. This requirement imposes a "one size fits all" regional structure which would place an unreasonable financial burden on all TOPs to both install and maintain additional hardware in each station or install and maintain multiple ICCPs between control centers. This requirement would place this financial burden on TOPs for nothing more than to replicate an RC function with no benefit to the BES. At no point in proposed Standard TOP-001- 3 does it require TOs to supply neighboring TOs with this data. Oncor requests R10.2 be removed from the standard due to lack of regional flexibility. Proposed R12 changes the existing requirement of operating outside an IROL for no longer than 30 minutes to "a continuous duration exceeding its associated IROL Tv". This requirement does not specify who determines the Tv of an IROL when multiple TOPs are involved in the circuit. Oncor believes that the 30 minute limit utilized in previous versions of this standard eliminates the possibility for disagreement. Oncor's recommendation is to keep the existing 30 minute time limit.
Response: The SDT deleted the term 'negatively' in a previous posting following the receipt of numerous industry comments suggesting that it was redundant as entities wouldn't be positively impacted by an outage. No change made. The requirement language is clear that Requirement R10, Part 10.2 only comes into play if the Transmission Operator finds that information necessary to determine SOL exceedances. If ERCOT is already operating without that information and is successfully meeting its obligations, then it must be the case that this information is not needed within ERCOT. Thus, ERCOT utilities would not be applying Requirement R10, Part 10.2. However, ERCOT is a special case dictated by its own rules and geography. Such a		

Organization	Yes or No	Question 1 Comment
statement would not necessarily be true in other areas. Requirements are written on a continent-wide basis and thus the SDT believes the wording in Requirement R10, Part 10.2 is correct as stated. However, if a Transmission Operator does require Real-time data from a neighboring Transmission Operator, that Transmission Operator should be able to leverage Transmission Operator – Reliability Coordinator communications to obtain such data and not have to install additional Transmission Operator – Transmission Operator datalinks. No change made. There are already requirements and procedures in place that specify that the Reliability Coordinator determines IROLs and the associated T_v. See approved FAC-011-2. No change made.		
Ameren	No	In our opinion, changes in this version were not significant and the drafting team has not addressed our concerns. (1) We have concerns on what constitutes "Operating Instructions", and over how an entity is to prove compliance once this standard becomes effective. We believe that "Reliability Directives", would be used infrequently under emergency type situations, compared to "Operating Instructions", everyday, common tasks, such as switching, would open up TOP's to an very burdensome way of documenting compliance. (2) We are concerned that the operator will have to focus less attention on the actual operation of the system, and more attention to collecting evidence for future audits. (3) We also have concerns about removing the terminology of EOP-001-1a; R1(and other requirements with similar language) that: “Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.” We believe that how entities choose to exercise that authority should be determined by each entity, based on their situation. (4) Over the years, the industry has clearly learned what a “Reliability Directive” means and we should not undo this concept, and avoid the confusion that it could create. In addition, the RSAWs introduce the concept of using BES events as a screening tool. We were not able to locate any such information in the Reliability Standard itself, nor

Organization	Yes or No	Question 1 Comment
		does the standard give guidance on when there are no BES events for the period being audited.
Response: The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should not attempt such differentiation. Operators should never be concerned about collecting audit evidence while operating the system. That should be done off-line and after-the-fact. The authority type requirements have been deleted as redundant as described in the mapping document. Reliability Directive was never an officially FERC approved term and confusion over what a reliability directive was or wasn't is what led to the revision of the COM standards and the creation of the definition of Operating Instruction. The appropriate measures include statements that an attestation that no events have occurred is sufficient evidence. No change made.		
Indiana Municipal Power Agency	No	IMPA does not agree with the use of Operating Instruction within this standard and does not agree with the SDT comments on how the RSAW will be used to "constrain" the potential amount of data an entity will need to provide to an auditor. NERC standards should be able to stand alone and not depend on RSAWs for guidance, especially since entities are audited to the requirements within a standard and not the RSAW. The RSAW states that auditors are encouraged to monitor compliance during the most "critical" events on the entity's system. Once an auditor states that all Operating Instructions are critical to the BES, then data for all Operating Instructions will need to be supplied to the auditor or a listing of the Operating Instructions for the compliance period with a follow up of evidence (the entity still needs to keep all the evidence for every Operating Instruction for the compliance period just in case that is the one selected). By changing the "reliability directive" wording to "Operating Instruction" within requirements R3 and R5 of TOP-001-3, the SDT has increased the administrative burden on entities who receive Operating Instructions from their TOP and BA. Once again increasing the administrative burden on

Organization	Yes or No	Question 1 Comment
		entities is the opposite theme of the RAI program which has a goal of helping the industry to concentrate on the “risk” to the BES.
Response: The SDT does not agree that it has increased the burden on entities to comply with these requirements and that sufficient safeguards have been put in place through data retention, measures, and RSAW language to prevent an undue burden on entities. No change made.		
CenterPoint Energy Houston Electric LLC	No	R10.2 - CenterPoint Energy agrees with the deletion of the phrase “non-BES” and appreciates the SDT’s consideration of industry comments. However, as stated in the previous round of comments, CenterPoint Energy strongly disagrees with the addition of 10.2 into the TOP Standards, specifically “neighboring Transmission Operator Areas”. CenterPoint Energy agrees with the Functional Model that it is the RC’s responsibility to monitor the wide area. In addition, CenterPoint Energy believes the SDT has overreached in its interpretation of paragraph 60 of the NOPR. CenterPoint Energy’s reading of paragraph 60 finds vague references to monitoring and analysis capabilities but no specific directives to expand the TOP’s view into another TOP Area. Also, CenterPoint Energy is concerned this will create confusion among registered entities as to who exactly has the responsibility to monitor and take action. Furthermore, CenterPoint Energy is not in favor of the most recent version of 10.2 where language referencing, “...identified as necessary by the Transmission Operator...” has been removed. As long as R10.2 remains CenterPoint Energy cannot support the proposed Standard and therefore strongly recommends the SDT delete R10.2. R13. - CenterPoint Energy agrees that an RTA should be run every 30 minutes, however during such events that could occur outside of the System Operator’s control (Ex. Loss of ICCP data); there should be a caveat as to when exceeding the 30 minutes becomes a violation. CenterPoint Energy suggests the following language: Each Transmission Operator shall

Organization	Yes or No	Question 1 Comment
		ensure that a Real-time Assessment is performed at least once every 30 minutes. In instances where a Real-Time Assessment cannot be performed (i.e. loss of ICCP data) the TOP shall take immediate action to restore Real-Time Assessment functionality.

Response: The requirement language is clear that Requirement R10, Part 10.2 only comes into play if the Transmission Operator finds that information necessary to determine SOL exceedances. If ERCOT is already operating without that information and is successfully meeting its obligations, then it must be the case that this information is not needed within ERCOT. Thus, ERCOT utilities would not be applying Requirement R10, Part 10.2. However, ERCOT is a special case dictated by its own rules and geography. Such a statement would not necessarily be true in other areas. Requirements are written on a continent-wide basis and thus the SDT believes the wording in Requirement R10, Part 10.2 is correct as stated. However, if a Transmission Operator does require Real-time data from a neighboring Transmission Operator, that Transmission Operator should be able to leverage Transmission Operator – Reliability Coordinator communications to obtain such data and not have to install additional Transmission Operator – Transmission Operator datalinks. No change made.

The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:

1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.

2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where

Organization	Yes or No	Question 1 Comment
normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement. 3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made.		
Consumers Energy Company	No	Comments: M3 and M5 are over reaching in requiring: In such cases, the Balancing Authority, Generator Operator, and Distribution Provider, and Load-Serving Entity shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. In the case of generating equipment this can and often is conditional with operating constraints under certain conditions. There may not be specific rules written out to cover all conditions. This is often within the authority of the plant operator concerning what can be done safely with the equipment.

Organization	Yes or No	Question 1 Comment
		This was not an evidence requirement in the current standards and does not need to be one now. We would be in favor of striking the above in both M3 and M5.
Response: If an operator is reacting to a particular situation by asserting that equipment limitations would be violated upon certain actions being taken, the SDT believes that the operator is acting based upon documented evidence stating so. The SDT also believes that if particular operating conditions are preventing an operator moving a unit to respond to a command that such constraints should have been made known to the Transmission Operator or Balancing Authority through the submission of revised operating limits, which should prevent the Transmission Operator or Balancing Authority from requesting such movement. No change made.		
Flathead Electric Cooperative	No	The change related to sustained outage being one more than 30 minutes seems tight. 30 minutes isn't very long for an outage.
Response: The SDT believes that 30 minutes is an appropriate timeframe as it is consistent with other standards such as approved EOP-004-2. No change made.		
US Bureau of Reclamation	No	Reclamation continues to disagree with the use of the term Operating Instruction in TOP-001-3. The drafting team's response to concerns about use of the term "Operating Instruction" rather than reliability directive include "The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered" and "Reliability Directive was never approved by FERC and thus was never part of an officially approved standard. The SDT believes that the use of Operating Instruction in this standard is consistent with the purpose and intent of the COM standards and that the COM standards correctly captured the reliability need as indicated in FERC’s acceptance of the standards. In the FERC NOPR, it was made clear that the concept of a special type of communication for Emergency situations was not considered acceptable. Operating Instructions issued to generators are not intended to damage critical generating equipment or interfere with competing obligations (e.g., water delivery schedules for hydroelectric producers)."Reclamation respectfully disagrees with the drafting team's

Organization	Yes or No	Question 1 Comment
		interpretation. Reclamation believes that FERC Order directed NERC to define "directive" rather than extend the scope of the standard to all communications between entities regarding bulk electric system operations. The order stated that the proposed standard had defined "transmission operator directives only in emergencies, not normal or pre-emergency times." Reclamation agrees with FERC that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements)." In Reclamation's opinion, the FERC order only directed NERC to better define the term "directive" and allow directives to be issued during normal operations as well as pre-emergency and emergency situations. Reclamation does not believe that FERC required the standard to apply to all non-emergency conversations between GOPs, BAs, and TOPs, with mutually-agreed upon operating plans resulting from these conversations like the COM updates. In general, Reclamation believes that grid operations are a collaborative effort that balance competing obligations of generation, transmission, and distribution providers. Reclamation does not believe that Transmission Operators always understand or consider the equipment capabilities and limitations, or other obligations of generators, and without this understanding Transmission Operators should not have authority for every operating instruction to be mandatory. Reclamation believes that Balancing Authorities and Transmission Providers should be granted wide latitude to issue "directives," which could be defined as "mandatory operating instructions to address transmission system concerns," but directives should be clearly identified by the transmission operator as directives to inform the recipient of the critical nature of the instruction. As written, the standard would instead apply to all operating instructions in all situations, and essentially would allow transmission operators to dictate instructions without understanding competing safety, equipment,

Organization	Yes or No	Question 1 Comment
		regulatory and statutory (including environmental) concerns of generators. This is likely to degrade BES reliability because generator operators will no longer understand the criticality of transmission operator instructions identified as "directives." Reclamation does not believe that the requirements to comply with Reliability Directives in TOP-001 and IRO-001 should be invoked unless the Transmission Operator describes a mandatory instruction as a Reliability Directive. Reclamation appreciates the clarifying language changes in R16, M16, R17, and M17.
Response: The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement should refrain from attempting such differentiation. No change made. Thank you for your support.		
Ingleside Cogeneration, LP	No	Ingleside Cogeneration L.P. (ICLP) believes that the project team has found an excellent resolution to the issue surrounding “sub-100 kV” and “non-BES” element data. By relying on other standards such as FAC-011-2 - which allows the Reliability Coordinator to dictate that the TOP must consider such facilities while developing their SOLs - the intent is still captured in a binding manner. In addition, NERC’s BES exception process allows the forced registration of critical facilities, which clearly applies to those that would affect a System Operating Limit. The TOP still has the obligation and authority to derive/monitor every SOL, but is not subject to the opinion of a CEA who may think that the criteria used is insufficient. Unfortunately, no such insight has been employed to defuse the standoff related to the execution of “Operating Instructions”. The issue caught FERC’s attention originally as the term “Reliability Directive” was used in

Organization	Yes or No	Question 1 Comment
		the submission of TOP-001-2 - which only applied to situations where an Emergency was declared. The Commission felt that instructions issued by a BA/TOP during near-emergency and normal operating conditions should also be mandatory, which the in-effect version of TOP-001 does not preclude. (It uses the generic un-capitalized term “reliability directive” which can apply to most any communication requiring action by the recipient.) The attempt to clarify the proper situations where a reliability directive can be used, and the evidence required to demonstrate compliance, has led to this impasse. ICLP believes that the way TOP-001-3 is written now, a GOP will be expected to capture the fact that every Operating Instruction was performed, even in low-risk situations where status or routine action is requested. This works against the concept of risk-based compliance and adds an administrative burden that is disproportional to the expected benefits. ICLP believes there is an acceptable alternative. The project team can lessen the severity of the improper execution of an Operating Instruction as compared to a Reliability Directive. This would mean that any instruction not identified by the BA or TOP as a Reliability Directive would only carry a Low VRF if not executed properly - perhaps a High VRF if an EOP-004-2 defined Event took place as a result. Furthermore, the lack of documentation should not work against the recipient of an Operating Instruction, but would allow for mitigating considerations if a good faith attempt was made in its execution. This would encourage the GOP (in our case) to diligently capture every Operating Instruction, but would not lead to a violation when an understandable oversight took place.

Response: Thank you for your support.

The Commission has made it clear in its Orders that it does not consider it appropriate to differentiate Operating Instructions according to the status of the system at the time of issuance. The belief is that this will lead to confusion for operators and possibly set up bad operating practices as to how to respond to Operating Instructions. Therefore, the SDT believes that the requirement

Organization	Yes or No	Question 1 Comment
should not attempt such differentiation. The SDT believes that it has appropriately identified and considered the burden on entities to comply with these requirements and that sufficient safeguards have been put in place through data retention, measures, and RSAW language to prevent an undue burden on entities. No change made.		
Independent Electricity System Operator	No	1. We continue to have serious concerns over the proposed retirement of TOP-004-2 Requirement R4 without having some of the requirements in TOP-004-2 revised to address the reliability need for confirming and re-establishing valid SOLs/IROLs in an unknown or unstudied state. We believe that there are times when, following some power system event, when there are no derived set of limits - particularly transient stability limits. We believe that the revised TOP standards do not compel an entity to derive limits following such events within an acceptable time frame. That direction was clearly specified in the existing TOP-004-2 R4:R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. We believe that removal of this requirement, without adequately and clearly replacing it, significantly diminishes reliability. We submit the following detailed comments for consideration by the SDT: a. The SDT's response to our previous comment suggests there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. We are unable to find a requirement in the standard that stipulates the Operating Plan shall have guidance to adjust the limit until a new set of limits are analyzed and determined. This requirement doesn't appear to exist. b. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The above response addresses SOL exceedance only; but the issue we raised is on the need to re-establish SOLs themselves, which may not already exist for the

Organization	Yes or No	Question 1 Comment
		conditions encountered. How does an entity know if it has exceeded an SOL if an SOL was not previously developed or is invalidated by the prevailing conditions? c. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F. Furthermore the standard does not prohibit an entity from performing an RTA more frequently in response to an unplanned system event. The SDT's response suggests that the concept of confirming and re-establishing SOL's is covered in the entities' Operating Plan. An Operating Plan, consistent with the NERC definition, is general and predictive in nature and by itself does not mandate the confirmation or re-establishment of limits when in an unstudied state. The concept of confirming and re-establishing SOL's for the prevailing condition is only captured in the SOL Exceedance White Paper under the "Stability Limit Exceedance" section as follows: "Pre-determined Transient and voltage Stability limits must be re-established when changes in the system (both expected future changes and actual Real-time changes) occur that render these pre-determined limits invalid." This sentence is presented in a standard requirement language. We do not understand why this is not stipulated in the standard itself such that it becomes an enforceable requirement to address the potential reliability gap created by retiring TOP-004-2 Requirement R4. Having this language in a whitepaper does not make this mandatory. 2. We offer the following comments on three requirements in TOP-001-3:i. R7: We do not agree with the added qualifier "within its Reliability Coordinator Area" since we believe that all TOPs need to assist their neighbor TOPs regardless if they are in the same RC area. We propose to remove this qualifier from R7.ii.

Organization	Yes or No	Question 1 Comment
		R10: We understand the intent of the proposed changes to Parts 10.1 and 10.2, but these changes have made the two parts confusing and inconsistent. From a reliability standpoint, it is intuitive that a TOP needs to monitor all Facilities within its TOP area that may have an impact on SOLs/IROLs. Part 10.1 is unclear on this whereas Part 10.2 is more specific on the parameters of the concerned Facilities. We suggest adding the word "all" before "Facilities" in Part 10.1.iii. R11: This requirement is redundant with BAL-002 since the latter already requires a BA to assess all contingencies - which should include SPS operations resulting in generation and/or load reduction, to determine its reserve requirements. We suggest removing R11.

Response: The SDT understands the concern of moving to an unknown state which it interprets as a condition that has not been previously studied. However, the SDT believes that there is always either a set of limits in service or an Operating Plan which provides guidance to adjust the limit until a new set of limits are analyzed and determined. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined, what to do upon experiencing an SOL exceedance, and acceptable timeframes to mitigate SOL exceedances. The SDT believes that the situation described has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to Requirement R13, perform a Real-time Assessment every 30 minutes, and Requirement R14, implement Operating Plans to mitigate an SOL Exceedance, as well as the guidance provided on Operating Plans in Section F and the SOL Exceedance White Paper. Furthermore, the standard does not prohibit an entity from performing a Real-time Assessment more frequently in response to an unplanned system event. No change made.

R7 – The SDT believes that there must be coordination at the Reliability Coordinator level before a Transmission Operator provides assistance to an entity outside of its associated Reliability Coordinator Area. No change made.

R10 – The SDT believes that the new sentence structure employed in the previous posting alleviates any ambiguity or confusion. No change made.

R11- The SDT has investigated the BAL standards and believes that an explicit requirement for monitoring by the Balancing Authority is necessary. There are no specific requirements in BAL standards for the Balancing Authority to monitor. And the Commission has made it clear in previous Orders that one can't assume something based on other requirements that dictate certain actions. In this

Organization	Yes or No	Question 1 Comment
case, just because an entity has to adhere to requirements for AGC or DCS and that it can't do that without monitoring is not sufficient cause to not have a specific monitoring requirement. No change made.		
American Transmission Company, LLC	No	ATC recommends that the SDT consider removing the following language from the proposed "Real-time Assessment" definition: "known Protection System and Special Protection System status or degradation," The revised definition would be as follows: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) Reason for removal of the language: This language should be removed because it is unrealistic for entities to perform a new real-time assessment every 30 minutes that incorporates the necessary contingency definition changes driven by a protection system failures. EMS systems using real-time contingency analysis tools do not include contingency definitions for the myriads of potential tripping scenarios for various failed protection systems. Therefore, off-line analysis would need to be performed by the system operator or another employee. Because off-line analysis would need to be used, it is an unreasonable burden to have to perform this assessment every 30 minutes as would be required by the proposed Requirement R13.
Response: The definition of Real-time Assessment has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time. The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the		

Organization	Yes or No	Question 1 Comment
responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement: 1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim. 2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement. 3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating		

Organization	Yes or No	Question 1 Comment
Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made.		
Georgia Transmission Corp	No	(1) GTC requests the drafting team to develop separate requirements for the DP to comply with Operating Instructions received by the TOP and BA which is consistent with NERC's Functional Model relating to real-time switching activities at non-BES facilities. By making this change, the requirements will be made clearer that the Operating Instructions that the DP receive from the TOP with respect to the defined term Operating Instruction, correspond to switching non-BES facilities that "impact" the output of an Element of the BES (shed or shift load). GTC believes the typical scenario the drafting team is considering is from a TOP control center to a DP dispatch center that does not own BES equipment, but can impact the output of an Element of the BES (by shedding or shifting load). The aforementioned comments relating to DP switching non-BES facilities provides additional support of why the DP should be ungrouped with the BA and GOP which may own and operate BES facilities. This separation of BES vs non-BES associated with implementing Operating Instructions reduces the current ambiguity for those NERC registered DPs that are also registered as Transmission Owners but are not registered as Transmission Operators with respect to requirements R3 and R5. With the following changes made to the requirements, GTC would be comfortable voting affirmative on this standard: o Each Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator to reduce voltage, shed load, shift load, and/or implement system restoration plans on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. o Each Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority to reduce voltage,

Organization	Yes or No	Question 1 Comment
		shed load, or shift load on non-BES facilities unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. (2) If however, the current draft standard passes this ballot GTC would greatly appreciate for the Standard Drafting team to expand the Rationale for Requirement R3 corresponding with the DP by inserting the following language: As identified in the NERC functional Model, Distribution Provider's must perform switching tasks to implement voltage reduction, load shed, or as part of a system restoration plans as directed by the Transmission Operator or Balancing Authority. (3) This Standard does not apply to a Transmission Owner; will the drafting team confirm GTC's assumption that the recipient field personnel of an Operating Instruction who performs the switching inside "transmission stations" are assumed to be handled by the TOP via R1? (4) The recipient entities of Operating Instructions performed in the field that do not own control centers will rely on the operator logs and voice recordings of the issuing entities as compliance evidence. Those entities (issuing vs recipient) which may have different data retention periods for compliance enforcement protection increases compliance risk to recipient entities that have zero control over the data. This risk can be mitigated by incorporating a reasonable data retention period into the requirements that are consistent with compliance enforcement practices. It should be noted, that the 90 day retention period under section C of this standard does not align with any compliance enforcement Regional Entity expectations and only adds confusion.
Response: (1) and (2) –The SDT intent is that Operating Instructions will be issued in accordance with the Functional Model. No change made. (3) The SDT confirms the commenter's interpretation.		

Organization	Yes or No	Question 1 Comment
(4) The SDT believes that the data retention periods provided in the standard are fair and reasonable. No change made.		
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comments for consideration. 1. Requirement R1, R2, R3 and R4 - ReliabilityFirst continues to recommend there be a timeframe added to the requirement stating the allotted time the Entity has to inform its Transmission Operator of its inability to perform an Operating Instruction. Failure to do so could result in a situational awareness issue (i.e. lack of accurate data and information) for the System Operator that could jeopardize system reliability. Additionally, and absent a timeframe, compliance to this requirement becomes subjective and difficult to enforce. ReliabilityFirst understands that a finite timeframe may not be appropriate to be stated in the standard to cover all circumstances, but offers a suggestion to require the TOP to define its needs when issuing Operating Instructions. ReliabilityFirst suggests the following revised language for consideration. R1 - Each Transmission Operator shall act to address the reliability of its Transmission Operator Area via direct actions or by issuing Operating Instructions [along with allocated time constraints for notification if the Operating Instructions cannot be performed].R2 - Each Balancing Authority shall act to address the reliability of its Balancing Authority Area via direct actions or by issuing Operating Instruction [along with allocated time constraints for notification if the Operating Instructions cannot be performed].R4 - Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator [within the time constraints allocated by the Transmission Operator] of its inability to perform an Operating Instruction issued by its Transmission Operator...” R6 - Each Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Balancing Authority [within the time constraints allocated by the Balancing

Organization	Yes or No	Question 1 Comment
		Authority] of its inability to perform an Operating Instruction issued by that Balancing Authority." 2. Requirement R10, Part 10.1 and 10.2 - ReliabilityFirst believes the lead-in language in R10 ("...shall perform") does not read well with the two sub parts. ReliabilityFirst recommends the following for consideration in order to make the wording of the parent and sub parts read more clearly: a. 10.1 - Monitoring Facilities and the status of Special Protection Systems, within its Transmission Operator Area, and b. 10.2 - Obtaining and utilizing status, voltages, and flow data for Facilities and the status of Special Protection Systems, outside its Transmission Operator Area. 3. Requirement R12 - ReliabilityFirst requests clarification from the SDT for instances when a TOP identifies an IROL which is outside of the set of predefined identified IROLs, are the TOPs also required to not operate outside these unidentified IROLs per Requirement R12? 4. Requirement R14 - ReliabilityFirst believes the word "initiate" should be replaced with the word "execute". Because Operating Plans consist of "...a group of activities", we would not want to only require the TOP to start (i.e., initiate) the first activity of the Operating Plan, but execute all activities that are part of the Operating Plan to mitigate the issue at hand.

Response: 1. The SDT believes that it is counter to reliability to place a time tag on these requirements. The operator should be concentrating on the reliability issue and not be concerned with adhering to an arbitrary time period for informing entities. No change made.

2. The SDT believes the suggested change doesn't provide any additional clarity. No change made.

3. The Reliability Coordinator identifies IROLs. If the Reliability Coordinator has not identified an IROL and provided that information to the Transmission Operator, then the Transmission Operator would not know about the IROL and would operate according to the information it has in hand. If the Transmission Operator observes an anomaly that it can't explain, then good utility practice would

Organization	Yes or No	Question 1 Comment
dictate that it inform its Reliability Coordinator of this anomaly which should precipitate action on the part of the Reliability Coordinator. 4. The SDT believes the suggested change doesn't provide any additional clarity. No change made.		
Texas Reliability Entity, Inc.	No	WRT to Requirement 10: Should Remedial Action Scheme be used instead? How will an entity support "as necessary"? How will a CEA accept "as necessary"? Transmission Operator Area ignores a Transmission Operator that DIRECTS "the operations of the transmission facilities" and may cause a reliability gap in the Standard in this Interconnection. The VSLs are geared towards zero tolerance. Example- R8 appears to be a violation if one TOP is not informed. R10 High VSL is one item is not monitored (Is that one line?) The R8 VSL adding a component to the R8 Requirement that does not otherwise exist in R8. This VSL modification of the R8 Requirement weakens the Requirement's beneficial effect on the reliability of the BES. In effect, the VSL modification negates the requirement in R8 by adding at the end 'unless you can't'. The added phrase in the VSL needs to be added in the R8 Requirement, where it can be properly considered as part of the Requirement, or removed from the VSL. R8 VSL has the phrase "when conditions did permit such communications" added to the description of the violations. This phrase does not exist in the Requirement. If the SDT wishes to change the meaning of the Requirement it should add that quoted phrase to the Requirement itself. R16 VSL has unintentionally included "Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its" in

Organization	Yes or No	Question 1 Comment
		the VSL and the quoted section should be removed. Also change the two occurrences of “Balancing Authority” to “Transmission Operator”. R17 VSL has unintentionally included “Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its” in the VSL and the quoted section should be removed. The removal of the phrase "may be performed either a day ahead or as much as 12 months ahead” in the revised definition of Operational Planning Analysis may impact the Real-time reliability of the Reliability Coordinator Area. The issue is that the new definition only refers to next-day operations. There is a possible gap since a time frame for the evaluation of one day up to 12 months may not be considered by registered entities because of the removal of the subject language. This gap is compounded by the fact that the Time Horizons for most of the requirements are either Same Day or Real-Time.

Response: The change from Special Protection Scheme to Remedial Action Scheme will be performed as part of an overarching project to correct all standards and requirements once final approval of the definition is obtained. The term ‘as necessary’ provides for the entity that best knows the situation to make a determination as to what information it needs. The SDT can’t comment on how the CEA will interpret any aspects of the standard. The SDT fails to see how Transmission Operator Area causes a gap.

The SDT believes that the VSLs are not directed toward zero tolerance but does agree that the VSLs do apply to missing one element. No change made.

The SDT agrees and has deleted the phrase from the VSLs. See the red-lined standard for the change.

The SDT agrees and has deleted the language in both VSLs. See red-lined standard for the change.

The definition of Operational Planning Analysis has already been approved by industry and adopted by the Board. It was included with proposed TOP-001-3 for ease of reference and is not subject to change at this time. The SDT believes that the true requirement

Organization	Yes or No	Question 1 Comment
is to make certain that a next-day analysis is performed and that other timeframes are not mandatory. Proposed IRO-017-1 takes into account planning for other timeframes. No change made.		
Electric Reliability Council of Texas, Inc.	No	ERCOT respectfully submits the following comments: 1. Regarding Requirement R13, ERCOT requests clarification that Requirement R13 does not apply during time periods where entities lose telemetry or EMS (an abnormal or emergency condition). During such time periods, registered entities may not be able to perform a Real-Time Assessment within 30 minutes (per definition). The reliability standards contemplate and allow for emergency circumstances and emergency plans in other Reliability Standards. To ensure consistency, the SDT should provide clarification regarding the applicability of this requirement by either: limiting applicability to normal operating conditions; providing a metric for percentage of availability that constitutes compliance, or revising the requirement to account for system issues as mentioned. 2. ERCOT reiterates concerns regarding use of the term “Operating Plan” in Requirement R14. Because the definition of “Operating Plan” states that it is a “document”, use of the term “Operating Plan” may be too restrictive to allow for necessary actions to be taken as contemplated in Requirement R14 as most actions taken occur per procedures or constraint management plans, but the universe of responsive actions cannot be easily documented in a single “document”. To ensure that system operators have the flexibility needed to take whatever actions they deem necessary to mitigate an SOL, ERCOT suggests removal of the term Operating Plan. 3. ERCOT respectfully submits that Requirements R1 and R2 are unnecessary because they are redundant with other requirements for a BA and TOP in Same-Day and Real Time Operations. ERCOT suggests deletion of Requirements R1 and R2.

Organization	Yes or No	Question 1 Comment

Response: The SDT agrees that the rationale for Requirement R13 will provide needed clarification and has added wording as suggested. See summary consideration for actual wording. The SDT believes that the 30-minute requirement is correct, reasonable, and in concert with approved EOP-008-1. While approved EOP-008-1 does allow an entity 2 hours to restore functionality, it does not take away the responsibility to maintain an entity's obligations during that period. In fact, approved EOP-008-1 specifically spells out that continuing obligation. Proposed TOP-001-3 follows that line of thought through the wording in the requirement itself in addition to the clauses in the Board-adopted definition of Real-time Assessment that allows for alternative means of performing these assessments. In addition, the SDT would like to provide the following clarifications regarding proposed TOP-001-3, Requirement R13 and the 30-minute timeframe requirement:

1. 30 minutes is an established timeframe for assessments, appearing in approved IRO-008-1, Requirement R2, which has been in effect since October 2011. While that standard/requirement is only applicable to the Reliability Coordinator, it is addressing the exact same topic. Therefore, the SDT is obligated to use the approved language and construct of the previously approved requirement unless it can make a case that the situation is different for a Transmission Operator. The SDT does not believe that this is the case and to date, no commenter has presented evidence that would support such a claim.

2. Previous SDT comment responses have made clear that it doesn't expect automated methods to be perfect and run as designed every 30 minutes. It has stated that it is assuming that an entity will have or develop an Operating Plan to cover the situation where normal methods aren't operational. And the SDT has provided documentation in that regard in Section F of proposed TOP-001-3 where it describes what an Operating Plan should be and what it should cover for this situation. Now, any Operating Plan is probably going to require manual intervention, for example, to call up needed data, to bring into play a backup procedure, etc. A concern raised is what happens if the normal scheme fails at the 29th minute – how can I get my plan into operation quickly enough to cover my potential exposure? The SDT believes that the Operating Plan should include enough flexibility so that an operator can make a decision quickly. The SDT further believes that if an entity has made a good faith effort to exercise its Operating Plan within the 30-minute timeframe that the entity shouldn't be found to be out of compliance. In addition, the SDT has provided clarifying, non-substantive changes to the rationale for Requirement R13 (See summary consideration for actual wording.). However, the SDT has no authority as to what an auditor will do. The entity in question can always point to the SDT comment responses and the intent of the SDT with this requirement.

3. There are additional elements to the timing question that need to be considered as well. The requirement doesn't mandate a tool for the Real-time Assessment, but for most registered entities a tool such as RTCA is what is being used. And such tools are being run at time intervals much quicker than every 30 minutes. That means that every time RTCA runs successfully, the clock is re-started for this requirement. In other words, if RTCA runs at 0834, an entity has until 0904 before the requirement kicks in. In the

Organization	Yes or No	Question 1 Comment
meantime, (assuming a 5 minute interval which is long for most entities) RTCA runs at 0839, 0844, 0849, 0854, and 0859. Each time it runs, the clock is restarted and the 30 minute requirement is pushed back. This means that the scenario where the tool fails at the 29th minute may not be a realistic case. Depending on the time interval in play, an entity could have 25 minutes to get its Operating Plan implemented. For entities not relying on RTCA to perform its Real-time Assessment, failure of a tool is less likely to be a significant issue. No change made. Given the clarification provided in Section F regarding the SDT's intent with the use of Operating Plan, the SDT believes that the term is used correctly in the requirement. No change made. The intent of Requirements R1 and R2 is that the Balancing Authority and Transmission Operator must take some action in order to maintain the reliability of the BES and not whether the Balancing Authority or Transmission Operator succeeded in said action, and therefore, the SDT sees no reason to revise the current wording. No change made.		
Dominion	Yes	4. Applicability: Suggest that "4.5"be struck as Load Serving Entity was deleted from the applicability list of entities. Dominion suggests that the Rationale for Requirement R13: be modified to state, "...and the timeframe is copied from the approved IRO-008-1, Requirement R2 for consistency.", as the language is not verbatim from approved IRO-008-1 Requirement 2. M5 - Suggest the "(s)" behind Balancing Authority be removed to match R5.
Response: The SDT agrees and has corrected the typo. See redlined standard for change. The language cannot be verbatim as the two standards refer to different entities. The SDT sees no additional clarity being provided by the suggested change. No change made. The SDT agrees and has made the suggested change. See summary consideration for actual wording.		
PJM Interconnection	Yes	PJM supports the standard and appreciates the changes made by the SDT.
Response: Thank you for your support.		

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Third posting October 10, 2014 to November 10, 2014

Fourth posting December 3, 2014 to January 7, 2015

Proposed Action Plan and Description of Current Draft

This is the fifth posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
Presentation to the NERC Board of Trustees for adoption	January 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**

2. **Number: TOP-001-3**

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   See Project 2014-03 project page.

B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by its Balancing Authority unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. This change is in response to the Independent Experts Review Panel (IERP) recommendations. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic

communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_V. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and R15 through R20 and Measure M1 through M11, and M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by its Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform one known impacted Balancing Authorities or 5% or less of the known	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform two known impacted Balancing Authorities or more	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of the known impacted Balancing Authorities, whichever is greater, of	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas. OR, The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.	Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR, The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			communication channels between the affected entities.	associated communication channels between the affected entities.	channels between the affected entities.	unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.
R11	Real-Time Operations	High	N/A	N/A	The Balancing Authority did not monitor the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					balance within its Balancing Authority Area and support Interconnection frequency.	
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: (to be placed here when final location is available).

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

SAR posted for comment February 21, 2014 to March 24, 2014

First posting May 19, 2014 to July 2, 2014

Second posting August 6, 2014 to September 19, 2014

Third posting October 10, 2014 to November 10, 2014

Fourth posting December 3, 2014 to January 7, 2015

Proposed Action Plan and Description of Current Draft

This is the ~~fourth~~fifth posting of the revised standard under Project 2014-03 Revisions to the TOP/IRO Reliability Standards. The SDT is working under a deadline for filing the revised standards with FERC of January 31, 2015.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
Presentation to the NERC Board of Trustees for adoption	January 2014

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by Board of Trustees on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	TBD	Revisions under Project 2014-03	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Rationale - The definition for Reliability Directive is not needed due to the work in proposed COM-002-4 on the definition of Operating Instruction (see NOPR paragraph 64).

Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Rationale - Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Transmission Operations**
2. **Number: TOP-001-3**
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - ~~**4.5.**~~
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2014-03 project page.

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B. Requirements and Measures

Rationale: The NERC Glossary term Reliability Directive has been replaced throughout by Operating Instruction. The new definition covers the Project 2014-03 SDT intent.

New Requirements R1 and R2 added in response to IERP Report recommendations.

R1. Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M1. Each Transmission Operator shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.

R2. Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. *[Violation Risk Factor: High][Time Horizon: Same-Day Operations, Real-time Operations]*

M2. Each Balancing Authority shall have and provide evidence which may include but is not limited to dated operator logs, dated records, dated and time-stamped voice recordings or dated transcripts of voice recordings, electronic communications, or equivalent documentation, that will be used to determine that it acted to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.

Rationale for Requirement R3: Additional phrasing 'cannot be physically implemented' included for consistency with proposed IRO-001-4, Requirement R2. This term means that a Transmission Operator may request something to be done that is not physically possible due to its lack of knowledge of the system involved.

R3. Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M3. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by the Transmission Operator(s) unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Balancing Authority, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Transmission Operator's Operating Instruction. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M4. Each Balancing Authority, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with its Operating Instruction issued. If such a situation has not occurred, the Balancing Authority, Generator Operator, or Distribution Provider may provide an attestation.

Rationale: Requirements R5 and R6 added for consistency with requirements applying to Transmission Operators. Entity list compiled from Functional Model v5 items 27 and 28 for Balancing Authority.

R5. Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M5. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence that it complied with each Operating Instruction issued by ~~the~~its Balancing Authority~~(s)~~ unless such action could not be physically implemented or it would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. In such cases, the Transmission Operator, Generator Operator, and Distribution Provider shall have and provide copies of the safety, equipment, regulatory, or statutory requirements as evidence for not complying with the Balancing Authority's Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

R6. Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to comply with an Operating Instruction issued by ~~that~~its Balancing Authority. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-Time Operations]*

M6. Each Transmission Operator, Generator Operator, and Distribution Provider shall make available upon request, evidence which may include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Balancing Authority of its inability to comply with its Operating Instruction. If such a situation has not occurred, the Transmission Operator, Generator Operator, or Distribution Provider may provide an attestation.

Rationale for Requirement R7: 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. ~~'~~This change~~s~~ is in response to the Independent Experts Review Panel (IERP) recommendations. Any request for assistance from Transmission Operator A to Transmission Operator B in another Reliability Coordinator Area would be coordinated with its respective Reliability Coordinators to assure a wide-area view is being applied to the situation.

R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting Transmission Operator has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M7. Each Transmission Operator shall make available upon request, evidence that comparable requested assistance, if able, was provided to other Transmission Operators within its Reliability Coordinator Area unless such assistance could not be physically implemented or would have violated safety, equipment, regulatory, or statutory requirements. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic

communications, or other equivalent evidence in electronic or hard copy format. If no request for assistance was received, the Transmission Operator may provide an attestation.

Rationale for Requirement R8: Original Requirement R3 has been merged with original Requirement R5 in response to concerns raised in NOPR paragraphs 80 -83 to have consistent terminology and actions across all time horizons.

R8. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M8. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no such situations have occurred, the Transmission Operator may provide an attestation.

Rationale for Requirement R9: Additional terms added in response to SW Outage Report recommendation 15.

R9. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned ~~-~~outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-Time Operations]*

M9. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned ~~-~~outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If such a situation has not occurred, the Balancing Authority or Transmission Operator may provide an attestation.

Rationale for Requirement R10: New proposed Requirement R10 is derived from approved IRO-003-2, Requirement R1, adapted to the Transmission Operator Area. This new requirement is in response to NOPR paragraph 60 concerning monitoring capabilities for the Transmission Operator. New Requirement R11 covers the Balancing Authorities. Monitoring of external systems can be accomplished via data links.

R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized status, voltages, and flow data for Facilities and the status of Special Protection Systems as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order- to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M11. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that it monitors its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M12. Each Transmission Operator shall make available evidence to show that for any occasion in which it operated outside any identified Interconnection Reliability Operating Limit (IROL), the continuous duration did not exceed its associated IROL T_v. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If such a situation has not occurred, the Transmission Operator may provide an attestation that an event has not occurred.

Rationale for Requirement R13: The new Requirement R13 is in response to NOPR paragraphs 55 and 60 concerning Real-time analysis responsibilities for Transmission Operators and is copied from approved IRO-008-1, Requirement R2. The Transmission Operator's Operating Plan will describe how to perform the Real-time Assessment. The Operating Plan should contain instructions as to how to perform Operational Planning Analysis and Real-time Assessment with detailed instructions and timing requirements as to how to adapt to conditions where processes, procedures, and automated software systems are not available (if used). This could include instructions such as an indication that no actions may be required if system conditions have not changed significantly and that previous Contingency analysis or Real-time Assessments may be used in such a situation.

R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M13. Each Transmission Operator shall have, and make available upon request, evidence to show it ensured that a Real-Time Assessment was performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

Rationale for Requirement R14: The original Requirement R8 was deleted and original Requirements R9 and R11 were revised in order to respond to NOPR paragraph 42 which raised the issue of handling all SOLs and not just a sub-set of SOLs. The SDT has developed a white paper on SOL exceedances that explains its intent on what needs to be contained in such an Operating Plan. These Operating Plans are developed and documented in advance of Real-time and may be developed from Operational Planning Assessments required per proposed TOP-002-4 or other assessments. Operating Plans could be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an Operational Planning Assessment or a Real-time Assessment. The intent is not to have a 1,000 page document with every possible Contingency cited but to have a plan and philosophy that can be followed by an operator.

R14. Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M14. Each Transmission Operator shall have evidence that it initiated its Operating Plan for mitigating SOL exceedances identified as part of its Real-time monitoring or Real-time Assessments. This evidence could include but is not limited to dated computer logs showing times the Operating Plan was initiated, dated checklists, or other evidence.

R15. Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M15. Each Transmission Operator shall make available evidence that it informed its Reliability Coordinator of actions taken to return the System to within limits when a SOL was exceeded. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If such a situation has not occurred, the Transmission Operator may provide an attestation.

Rationale for Requirements R16 and R17: In response IERP Report recommendation 3 on authority.

R16. Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M16. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Transmission Operator has provided its System Operators with the authority to approve planned outages and maintenance of telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R17. Each Balancing Authority shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M17. Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

Rationale for Requirement R18: Moved from approved IRO-005-3.1a, Requirement R10. Transmission Service Provider, Distribution Provider, Load-Serving Entity, Generator Operator, and Purchasing-Selling Entity deleted as those entities will receive instructions on limits from the responsible entities cited in the requirement. Note – Derived limits replaced by SOLs for clarity and specificity. SOLs include voltage, Stability, and thermal limits and are thus the most limiting factor.

R18. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M18. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to operator logs, voice recordings, electronic communications, or equivalent evidence that will be used to determine if it operated to the most limiting parameter in instances where there is a difference in SOLs.

Rationale for Requirements R19 and R20 added for consistency with proposed IRO-002-4, Requirement R1. Data exchange capabilities are required to support the data specification concept in proposed TOP-003-3.

R19. Each Transmission Operator shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M19. Each Transmission Operator shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area.

R20. Each Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M20. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, or other evidence that it has data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and R15 through R20 and Measure M1 through M11, and M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of ninety calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v as specified in Requirement R12 and Measure M12 and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14.

Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Generator Operator, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Balancing Authority failed to act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R3	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Transmission Operator, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R4	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to comply with an Operating Instruction issued by its Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The responsible entity did not comply with an Operating Instruction issued by the Balancing Authority, and such action could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.
R6	Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The responsible entity did not inform its Balancing Authority of its inability to comply with an Operating Instruction issued by ~~that~~its Balancing Authority.
R7	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide comparable assistance to other Transmission Operators within its Reliability Coordinator Area, when requested and able, and the requesting entity had implemented its Emergency procedures, and such actions could have been physically implemented and would not have violated safety, equipment, regulatory, or statutory requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirements R8 and R9 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R8	Operations Planning, Same-Day Operations, Real-Time Operations	High	The Transmission Operator did not inform one known impacted Transmission Operator or 5% or less of the known impacted ~~other~~ Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas ~~when conditions did permit such communications~~. OR, The Transmission Operator did not inform one known	The Transmission Operator did not inform two known impacted Transmission Operators or more than 5% and less than or equal to 10% of the known impacted ~~other~~ Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas ~~when conditions did permit such communications~~. OR, The Transmission Operator did not inform two known	The Transmission Operator did not inform three known impacted Transmission Operators or more than 10% and less than or equal to 15% of the known impacted ~~other~~ Transmission Operators, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Transmission Operator Areas ~~when conditions did permit such communications~~. OR, The Transmission Operator did not inform three known impacted Balancing Authorities or more than 10% and less than or equal to 15% of	The Transmission Operator did not inform its Reliability Coordinator of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas ~~when conditions did permit such communications~~. OR The Transmission Operator did not inform four or more known impacted Transmission Operators or more than 15% of the known impacted Transmission Operators of its actual or expected operations that resulted in, or could have resulted in, an Emergency on those respective Transmission Operator Areas ~~when conditions did permit such communications~~. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impacted Balancing Authorities or 5% or less of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas ~~when conditions did permit such communications~~.	impacted Balancing Authorities or more than 5% and less than or equal to 10% of the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas ~~when conditions did permit such communications~~.	the known impacted Balancing Authorities, whichever is greater, of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas ~~when conditions did permit such communications~~.	The Transmission Operator did not inform four or more known impacted Balancing Authorities or more than 15% of the known impacted Balancing Authorities of its actual or expected operations that resulted in, or could have resulted in, an Emergency on respective Balancing Authority Areas ~~when conditions did permit such communications~~.
R9	Operations Planning, Same-Day Operations, Real-Time Operations	Medium	The responsible entity did not notify one known impacted interconnected entity or 5% or less of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and	The responsible entity did not notify two known impacted interconnected entities or more than 5% and less than or equal to 10% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more,	The responsible entity did not notify three known impacted interconnected entities or more than 10% and less than or equal to 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and	The responsible entity did not notify its Reliability Coordinator of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.	The responsible entity did not notify four or more known impacted interconnected entities or more than 15% of the known impacted entities, whichever is greater, of a planned outage, or an unplanned outage of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	Real-Time Operations	High	N/A	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1. OR, The Transmission Operator did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor one of the items listed in Requirement R10, Part 10.1 and did not obtain and utilize one of the items listed in Requirement R10, Part 10.2.	The Transmission Operator did not monitor Facilities and the status of Special Protection Systems within its Transmission Operator Area and did not obtain and utilize data deemed as necessary from outside its Transmission Operator Area.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R11	Real-Time Operations	High	N/A	N/A	The Balancing Authority did not monitor the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R12	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	Same-Day Operations, Real-Time Operations	High	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	Real-Time Operations	Medium	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL had been exceeded.
R16.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its ~~Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	Operations Planning, Same-Day Operations, Real-Time Operations	High	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its ~~Each Balancing Authority shall have, and provide upon request, evidence that could include but is not limited to a documented procedure or equivalent evidence that will be used to confirm that the Balancing Authority has provided its System Operators with the authority to approve planned outages and maintenance of its~~ telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R18	Operations Planning, Same-Day Operations, Real-time Operations	High	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in instances where there was a difference in SOLs.
R19	Operations Planning, Same-Day Operations, Real-time Operations	High	The Transmission Operator did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Transmission Operator did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R20	Operations Planning, Same-Day Operations, Real-time Operations	High	The Balancing Authority did not have data exchange capabilities with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~URL for~~ The SDT has created the SOL Exceedance White Paper as guidance on SOL issues and the URL for that document is: (to be placed here when final location is available).

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Implementation Plan

Project 2014-03 Revisions to TOP/IRO Reliability Standards

Requested Approvals

- TOP-001-3 Transmission Operations
- TOP-002-4 Operations Planning
- TOP-003-3 Operational Reliability Data
- IRO-001-4 Reliability Coordination - Responsibilities and Authorities
- IRO-002-4 Reliability Coordination — Analysis Tools
- IRO-008-2 Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-2 Reliability Coordinator Data Specification and Collection
- IRO-014-3 Coordination Among Reliability Coordinators
- IRO-017-1 Outage Coordination

Requested Retirements (two groups of standards)

1. **Existing Approved Standards**
    - TOP-001-1a Reliability Responsibilities and Authorities
    - TOP-002—2.1b Normal Operations Planning
    - TOP-003-1 Planned Outage Coordination
    - TOP-004-2 Transmission Operations
    - TOP-005-2a Operational Reliability Information
    - TOP-006-2 Monitoring System Conditions
    - TOP-007-0 Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
    - TOP-008-1 Response to Transmission Limit Violations
    - IRO-001-1.1 Reliability Coordination — Responsibilities and Authorities
    - IRO-002-2 Reliability Coordination — Facilities
    - IRO-003-2 Reliability Coordination – Wide Area View
    - IRO-004-2 Reliability Coordination – Operations Planning
    - IRO-005-3.1a Reliability Coordination — Current Day Operations
    - IRO-008-1 Reliability Coordinator Operational Analyses and Real-time Assessments
    - IRO-010-1a Reliability Coordinator Data Specification and Collection
    - IRO-014-1 Coordination Among Reliability Coordinators
    - IRO-015-1 Notifications and Information Exchange Between Reliability Coordinators
    - IRO-016-1 Coordination of Real-time Activities Between Reliability Coordinators
    - PER-001-0.2 Operating Personnel Responsibility and Authority

2. **Filed with FERC but not approved** – these standards were filed with FERC but never approved and will be retired as part of this project. Upon Board approval of replacement standards, NERC will request the Board to rescind its approval of these standards and petition FERC to withdraw its petition for approval of these standards:
    - TOP-001-2 Transmission Operations
    - TOP-002-3 Operations Planning
    - TOP-003-2 Operational Reliability Data
    - IRO-001-3 Reliability Coordination - Responsibilities and Authorities
    - IRO-002-3 Reliability Coordination — Analysis Tools
    - IRO-005-4 Reliability Coordination — Current Day Operations
    - IRO-014-2 Coordination Among Reliability Coordinators
    - PRC-001-2 System Protection Coordination

Prerequisite Approvals[1]

Definition of Operating Instruction (filed with proposed COM-002-4).
COM-001-2 – Communications (filed with proposed COM-002-4)

Revisions to Defined Terms in the NERC Glossary

The Standards Drafting Team proposes retiring the following Board-approved definitions:	
Reliability Directive	Original definition – approved by the Board but never adopted by FERC; will be withdrawn as part of this project, consistent with the approach for the standards that were filed with FERC and not approved. Definition: *A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.*
The Standards Drafting Team proposes revising the following Board-approved definitions:	
Operational Planning Analysis	**Original definition**: *An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).* **Revised definition**: *An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels;*

[1] In the event approval of COM-001-2 and the definition of Operating Instruction do not occur prior to the approval of the standards and definitions revised or developed in Project 2014-03, the currently enforceable standards and definitions would remain effective until those approvals have occurred, and the new or revised standards in Project 2014-03 shall become effective concurrent with the effective date of COM-001-2 and the definition of Operating Instruction.

	Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment	**Original definition**: *An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.* **Revised definition**: *An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

The definitions were revised in response to issues raised in NOPR paragraphs 55, 73, and 74 on analysis and monitoring of SOLs in all time horizons, NOPR paragraph 70 (updating study results in Real-time), and NOPR paragraph 78 (Protection System coordination). The phase angle item was added in response to SW Outage Report recommendation 27.

Background

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

On February 12, 2014, the Standards Committee appointed a Standard Drafting Team to take on the task of revising the aforementioned standards in response to the NOPR issues and the recommendations made by the Independent Expert Review Panel, the IRO FYRT, and the SW Outage Report and this implementation plan is developed from the changes made to the standards revised by that project.

General Considerations

The twelve month implementation period for all of the standards except TOP-003-3 and IRO-010-2 is intended to allow time for entities to update processes and train operators on the revised requirements. All of the Requirements in proposed TOP-003-3 and IRO-010-2 except TOP-003-3, Requirements R5 and IRO-010-2, Requirement R3 become effective three months earlier, in order to provide recipients of data requests from their Reliability Coordinators, Transmission Operators, and/or Balancing Authorities time to respond to the request for data.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Owner
- Transmission Operator
- Distribution Provider
- Generator Owner
- Generator Operator
- Load-Serving Entity
- Planning Coordinator
- Transmission Planner

Effective Date for Standards

1. **If the Prerequisite Approvals occur on or before Approval of the standards in Project 2014-03:**

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become

effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests.

2. If the approval of the standards in Project 2014-03 occurs concurrent with or before the Prerequisite Approvals:

- **For all standards except proposed TOP-003-3 and proposed IRO-010-2:**
  The standard shall become effective concurrently with COM-001-2 and the definition of Operating Instruction.

- **For proposed TOP-003-3:**
  All requirements except Requirement R5 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date COM-001-2 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

  Requirement R5 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definition of Operating Instruction is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The reason for the difference in effective dates for proposed TOP-003-3 is to allow applicable entities to have time to properly respond to the data specification requests.

- **For proposed IRO-010-2:**
  Requirement R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirements R1 and R2 shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definition of Operating Instruction is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, Requirement R3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Standards for Retirement:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

- **Definition of Reliability Directive:**
  Midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date that the standards in Project 2014-03 are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall be retired at midnight of the day before the first day of the first calendar quarter that is twelve (12) months after the date the standards in Project 2014-03 are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Definitions

The definitions of Operational Planning Analysis and Real-time Assessment shall become effective on the first day of the first calendar quarter that is ten (10) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definitions to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ten (10) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The definitions are used in proposed IRO-010-2, Requirements R1 and R2 and in proposed TOP-003-3, Requirements R1 and R3 so it is necessary that the definitions become effective concurrent with those requirements.

The two definitions are also employed in the following proposed project standards: TOP-001-3, TOP-002-4, and IRO-008-2. These definitions are not used in any other standards, either approved or in development in any other project.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Laura.Hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-03 Revisions to the TOP/IRO Reliability Standards		
Date Submitted:	February 12, 2014		
SAR Requester Information			
Name:	David Souder		
Organization:	PJM		
Telephone:	610-666-4795	E-mail:	souder@pjm.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR in response to these petitions. The NOPR proposed to remand the proposed TOP and IRO Standards. In the NOPR, the Commission raises a concern that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." For example, the Commission cites the fact that the proposed TOP standards do not require Transmission Operators to plan and operate within all System Operating Limits ("SOLs"), which is a requirement in the currently effective standards.

On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR. This deferral would provide an opportunity for the industry, NERC, and FERC to work toward a common understanding and afford time to review the proposed TOP and IRO standards through the NERC standards development process to address the concerns set forth in the NOPR. That motion to defer action was granted by the Commission on January 14, 2014.

SAR Information

Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-03 Revisions to TOP/IRO Reliability Standards to address the concerns expressed in the NOPR while fulfilling the goals of the original projects: Project 2006-06 Reliability Coordination and Project 2007-03 Real-time Operations. In addition, the SDT should review the goals of Project 2009-02 Real-time Monitoring and Analysis Capabilities and consider whether to incorporate revisions to the TOP and/or IRO standards to address those goals in Project 2014-03.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standards to allow Reliability Coordinators, Transmission Operators, and Balancing Authorities to operate the interconnected transmission system in a safe and reliable manner.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the TOP and IRO Reliability Standards to address the issues raised in the NOPR, while ensuring that the revisions continue to address directives previously assigned to the TOP and IRO standards under Projects 2007-03 and 2006-06. If it is decided to handle the goals of Project 2009-02 within Project 2014-03, then the directives assigned to Project 2009-02 will be addressed as well. In addition, the suggestions from the Independent Expert Review Project will be reviewed, a directive dealing with monitoring responsibilities for the Reliability Coordinator will be resolved, and other IRO standards will be examined for consistency purposes.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDT shall: 1. Revise the TOP/IRO Reliability Standards filed under Projects 2007-03 and 2006-06 to address concerns expressed in the NOPR a. Use the inputs from technical conferences to advise actions 2. Consider the comments and suggestions in the Independent Expert Review Report 3. Review the IRO Reliability Standards not included in the original Project 2006-06 for coordination with any changes made for this project (see list of related standards) 4. Decide whether to handle the goals of Project 2009-02 within Project 2014-03; and if it does so decide, then also address the directives assigned to Project 2009-02. 5. Address the following directive from Order 693, paragraph 1855 so that all monitoring responsibilities for the Reliability Coordinator are included in the IRO family of standards: *"Since a reliability coordinator is the highest level of authority overseeing the reliability of the*

SAR Information
Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."
6. Modify the measures, Violation Risk Factors (VRF), and Violation Severity Levels (VSL) as necessary to address modified requirements

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner

Reliability and Market Interface Principles	
	to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-003-2 IRO-004-2 IRO-006-5	Needs to be reviewed for language and terminology consistency with revisions made in this project

Related Standards	
IRO-008-1	
IRO-009-1	
IRO-010-1a	
IRO-015-1	
IRO-016-1	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Notice of Request to Waive the Standard Process

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

As required by Section 16 of the NERC Standard Processes Manual (SPM), this is official notice to stakeholders that the leadership of the Project 2014-03 Revisions to TOP and IRO Reliability Standards Drafting Team, the Project Management Oversight Subcommittee (PMOS) liaison for that project, Standards Committee (SC) chair, and NERC Standards Staff (Requesters) are requesting that the SC consider a waiver of the Standard Processes Manual. The Requesters ask to shorten the next formal comment and ballot period for draft standard TOP-001-3, and any subsequent comment formal comment and ballot periods prior to final ballot for that standard, from 45 days to 30 days, and to shorten the final ballot for TOP-001-3 from ten days to seven days, in order to meet a regulatory deadline. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process.

The SC will meet via teleconference to consider this waiver request no earlier than Thursday, October 9, 2014 (to comply with the five business day notice required by Section 16 of the SPM). The Standards Committee's teleconference will be noticed through an announcement and posted on the NERC website. Additional details about the waiver request are included below, and should a waiver be granted by the SC, it will be posted on the project page.

Justification for Current Waiver Request

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

On November 21, 2013, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) proposing to remand three revised TOP Reliability Standards and four revised IRO Reliability Standards. In the NOPR FERC stated that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards." On December 20, 2013, NERC filed a motion requesting that the Commission defer action on the NOPR until January 31, 2015 to provide NERC and the industry the opportunity to thoroughly examine the technical concerns raised in the NOPR and afford time to review the proposed

TOP and IRO Standards through the NERC standards development process to ensure that a technically justified set of solutions is in place for reliability.

NERC's motion to defer action was granted on January 14, 2014.

The drafting team has developed a set of eight revised standards and one new standard to replace the standards that the NOPR proposed to remand. The standards have been posted for two 45-day comment periods and ballots, and in the ballot ending September 19, 2014, eight of the nine standards achieved greater than the required two-thirds weighted segment approval.

The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Laura Hussey,
Director of Standards Development, at laura.hussey@nerc.net or at 404-446-2560.

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Agenda Item 2
Standards Committee
October 9, 2014

Waiver Authorization for Project 2014-03: Revisions to TOP and IRO Reliability Standards

Action

Authorize a waiver of the Standard Processes Manual (SPM) to:

a) shorten the next additional formal comment period (and any subsequent additional formal comment periods) for draft standard TOP-001-3 from 45 days to 30 days, with a ballot and non-binding poll during the last seven days of the 30 day period; and

b) shorten the final ballot period from ten days to seven days.

Background

The leadership of the TOP/IRO Standard Drafting Team, NERC staff, and the PMOS liaison and Standards Committee (SC) chair have requested a waiver of the NERC Standards Processes Manual (SPM) as described in the actions above. Section 16 of the SPM provides for the granting of waivers for regulatory deadlines and where the SC determines that a modification to a proposed Reliability Standard has already been vetted by the industry through the standard development process. As required in Section 16, NERC provided stakeholders with notice of these waiver requests on October 2, 2014. If a waiver is authorized, NERC staff will post notice of the waiver on the project page and notify the NERC Board of Trustees Standards Oversight and Technology Committee.

On April 16, 2013, NERC submitted two petitions requesting FERC approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the "TOP Standards") to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the "IRO Standards") to replace six currently-effective IRO standards.

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The drafting team met to review stakeholder feedback on September 30 and October 1, and based on that feedback has made substantive revisions to TOP-001-3. The shortened comment period and ballot for TOP-001-3 serves two important purposes. First, should it be necessary to conduct more than one additional ballot to reach consensus on TOP-001-3, the shortened comment period will allow for one additional comment period and ballot while still allowing the nine standards to be filed with FERC by the January 31, 2015 deadline. Second, shortening the ballot period from ten days to seven days provides additional time during the comment period for drafting team outreach prior to the start of the ballot. This outreach may be important to ensure stakeholder support for the standard.

Finally, shortening the final ballot period for TOP-001-3 from ten days to seven days provides scheduling flexibility that may be required to achieve the necessary milestones prior to filing (including possibly scheduling a special call for NERC Board adoption), while still allowing NERC and the industry to successfully meet the January 31, 2015 filing deadline. If NERC is unable to meet the January 31, 2015 deadline, FERC may proceed with its proposed remand of the TOP and IRO standards.

Project 2014-03 – Revisions to TOP and IRO Reliability Standards

Mapping Document | Updated December 2014

This mapping document showing the translation of Requirements in the following currently-enforceable standards to revised or new standards developed in Project 2014-03:

- IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities
- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination – Wide-Area View
- IRO-004-2 — Reliability Coordination — Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-008-1 — Reliability Coordinator Operational Analyses and Real-time Assessments
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-3 — Monitoring System Conditions[1]
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

[1] TOP-006-2 is the currently enforceable version of this standard; TOP-006-3 was developed in response to a request for interpretation seeking clarification of Requirement R1 and does not substantively change the Requirements of TOP-006-2. In its NOPR proposing to remand the TOP and IRO standard, FERC proposed to approve TOP-006-3. The drafting team has mapped the Requirements in the new standards to TOP-006-3 because the Parts of Requirement R1 in TOP-006-3 more clearly delineate which entity has responsibility.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	The SDT proposes retiring the requirement as it is addressed in the NERC Rules of Procedure, January 30, 2014: **Section 503.2 (2.1)** “Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).” **Section 501 (1.4)** “**1.4** For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall: **1.4.1** Ensure that all areas are under the oversight of one and only one Reliability Coordinator. **1.4.2** Ensure that all Balancing Authorities and Transmission operator entities are under the responsibility of one and only one Reliability Coordinator. **1.4.3** Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator. **1.4.4** Ensure that all loads and generators are under the responsibility and control of one and only one Balancing Authority.”
R2. The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	**The SDT is proposing to retire this requirement.** The SDT proposes retiring Requirement R2 as the regional reliability plan is a high level overview “how” document that shows how a Reliability Coordinator will comply with other NERC Standards. As a result, this requirement is administrative and redundant to other measureable and enforceable requirements within the standards. Since the requirement is generally administrative, it does not materially impact the reliability of the BES. The Reliability Plan concept is a holdover from the transition period from the Operating Policies to the Version 0 standards and was used extensively in the readiness evaluation process by the Operating Committee. The template used for the Reliability Plan is actually an outline of Operating Policy 9. The material included in the plan was a description of how an entity satisfied the specific functional areas under Policy 9. With the transition of Policy 9 to the IRO and other standards, the items addressed in

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	the reliability plans are inherently addressed in the body of other more measurable Reliability Standards.
R3. The Reliability Coordinator shall have clear decision-making authority to act and direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	**This requirement is replaced by proposed IRO-001-4, Requirements R1 and R2.** The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent when the requirement states that the Reliability Coordinator must act, or by issuing Operating Instructions. **Proposed IRO-001-4, Requirements R1 and R2:** **R1**. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4. Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	**The SDT is proposing to retire this requirement.** The SDT contends that approved IRO-001-1.1, Requirement R4 is redundant with NERC Rules of Procedure, Section 500 (January 30, 2014) and should be retired from the standard. **(Section 501)** "The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards." **(Section 508)** Provisions Relating to Coordinated Functional Registration (CFR) Entities In addition to registering as an entity responsible for all functions that it performs itself, multiple entities may each register using a CFR for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function. The CFR submission must include a written agreement that governs itself and clearly specifies the entities' respective compliance responsibilities. The Registration of the CFR is the complete

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Registration for each entity. Additionally, each entity shall take full compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements it has registered for in the CFR. Neither NERC nor the Regional Entity shall be parties to any such agreement, nor shall NERC or the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the CFR.
R5. The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	The SDT is proposing to retire this requirement consistent with Paragraph 81 criteria as it is strictly administrative in nature.
R6. The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	The SDT is proposing to retire this requirement. The Reliability Coordinator may delegate tasks but cannot delegate the responsibility for these tasks. Therefore, it is not necessary to mandate that delegated tasks must be carried out by certified personnel as it is the responsibility of the Reliability Coordinator to ensure that the task is carried out.
R7. The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.
R8: Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability	This requirement is replaced by proposed IRO-001-4, Requirements R2 and R3. **Proposed IRO-001-4, Requirements R2 and R3:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2.

Standard IRO-001-1.1 — Reliability Coordination - Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinator may implement alternate remedial actions.	
R9. The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	The SDT is proposing to retire this requirement as it is redundant with the definition of Reliability Coordinator in Functional Model v5. The NERC Functional Model Version 5 defines the Reliability Coordinator function as follows: "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." An entity performing Reliability Coordinator services must meet this definition.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	The first sentence of this requirement is replaced by proposed COM-001-2 Requirement R1 for voice links and proposed IRO-002-2 Requirement R1 for data links. The second sentence of this requirement is covered by approved PER-004-2 Requirement R1 so to eliminate redundancy, that part of the requirement is not proposed to be replaced. **Proposed COM-001-2, Requirement R1:** **R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R1:** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Approved PER-004-2, Requirement R1:** **R1.** Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.
R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3, Part 3.3. **Proposed IRO-010-2, Requirements R1 and R3, Part 3.3:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **R3.** Part 3.3. A mutually agreeable security protocol
R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability	This requirement is replaced by proposed COM-001-2 Requirement R1 and proposed IRO-002-4 Requirement R2. **Proposed COM-001-2, Requirement R1:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	**R1.** Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): 1.1 All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. 1.2 Each adjacent Reliability Coordinator within the same Interconnection. **Proposed IRO-002-4, Requirement R2:** **R2**. Each Reliability Coordinator shall have data exchange capabilities with Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	This requirement is replaced by proposed IRO-002-4, Requirements R4 and R5. **Proposed IRO-002-4, Requirements R3 and R4:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to	This requirement is replaced by proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	
R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	This requirement is replaced by proposed IRO-008-5, Requirement R5 and the proposed definition of Real-time Assessment. **Proposed IRO-008, Requirement R4:** **R4**. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	This requirement is replaced by proposed IRO-002-4, Requirement R3 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2**. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have	This requirement is replaced by proposed IRO-002, Requirement R2 and approved EOP-008-1, Requirement R1, Part 1.6.2. **Proposed IRO-002-4, Requirement R2:**

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
procedures in place to mitigate the effects of analysis tool outages.	**R2.** Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunications, monitoring and analysis capabilities. **Approved EOP-008-1, Requirement R1, Part 1.6.2:** **R1. Part 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	Replaced with proposed IRO-002-4, Requirement R3. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R2. Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	Replaced with proposed IRO-002-4, Requirement R3 and revised definitions of Operational Planning Analysis and Real-time Assessment. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	This requirement is replaced by proposed IRO-001-4, Requirement R1 since Operating Instructions, regardless of what timeframe they are issued for, are issued in a Real-time environment. In addition, roles for entities identified in the Operating Plans built from Operational Planning Analyses are communicated in proposed IRO-008-2, Requirement R3. **Proposed IRO-001-4, Requirement R1:** R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. **Proposed IRO-008-2, Requirement R3:** R3. Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s).

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: **R1.1** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading. **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. **R1.4.** System real and reactive reserves (actual versus required). **R1.5**. Capacity and energy adequacy conditions. **R1.6.** Current ACE for all its Balancing Authorities. **R1.7**. Current local or Transmission Loading Relief procedures in effect. **R1.8.** Planned generation dispatches. **R1.9.** Planned transmission or generation outages. **R1.10.** Contingency events.	Replaced by proposed IRO-002-4, Requirements R3 and R4. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4**. Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard (CPS) and	The first sentence is replaced by proposed IRO-002-4, Requirement R3. The second sentence is covered by approved EOP-002-3.1a, Requirement R8 and can be retired. **Proposed IRO-002-4 Requirement, R3**:

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Disturbance Control Standard (DCS) requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	**R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Approved EOP-002-3.1a, Requirement R8:** **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	The SDT proposes retiring this requirement as it has been superseded by approved EOP-010-1, Requirements R1 through R3. **Approved EOP-010-1, Requirements R1 to R3:** **R1** Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: **1.1** A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. **1.2** A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. **R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. **R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: **3.1.** Steps or tasks to receive space weather information. **3.2**. System Operator actions to be initiated based on predetermined conditions. **3.3**. The conditions for terminating the Operating Procedure or Operating Process.
R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	This requirement has been replaced by proposed IRO-008-2, Requirements R3, R5 and R6. **Proposed IRO-008-2, Requirement R3:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	This requirement is replaced by proposed IRO-001-4, Requirement R1 and proposed IRO-002-34 Requirements R3 and R4. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-002-4, Requirement R3: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.
R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	The first sentence is replaced with proposed IRO-008-2, Requirement R2. The issue of CPS and DCS is covered in approved EOP-002-3.1, Requirements R6, R7, and R8. The second sentence is replaced by the proposed IRO-017-1, Requirement R1 as well as through the proposed definitions of Operational Planning Analysis and Real-time Assessments. Generator Operators are not included in proposed IRO-017-1 as the SDT believes that Generator Operator outage information will be sent to the respective Transmission Operators and Balancing Authorities and then sent on to the Reliability Coordinators through those entities. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-017-1, Requirement R1:** **R1.** Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. **Approved EOP-002-3.1, Requirements R6, R7, and R8:** **R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. **R6.2**. Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5**. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and **R7.2**. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R8.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-001-4, Requirement R1. **Proposed IRO-002-4, Requirement R3:** **R3**. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-001-4, Requirement R1:** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.
R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator	The first sentence is replaced by proposed IRO-002-4, Requirements R3 and R4. The second sentence is replaced by proposed IRO-010-2, Requirements R1, Part 1.2, and R3.

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	**Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed IRO-002-4, Requirement R4:** **R4.** Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. **Proposed IRO-010-4, Requirement R1, Part 1.2:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **Proposed IRO-010-4, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.
R10. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	For Reliability Coordinators, this requirement is replaced by approved IRO-009-1, Requirement R5. For Transmission Operators, Balancing Authorities, and Generator Operators, this requirement is replaced by proposed TOP-001-3, Requirement R18. The Transmission Service Provider and Purchasing-Selling Entity will receive instructions on limits from the previously cited entities and can thus be deleted from the requirement. **Approved IRO-009-1, Requirement R5:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R11. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	This requirement is replaced by proposed MOD-001-2, Requirement R2. **Proposed MOD-001-2, Requirement R2:** **R2**. Each Transmission Service Provider that determines Available Flowgate Capability (AFC) or Available Transfer Capability (ATC) shall develop an Available Transfer Capability Implementation Document (ATCID) that describes the methodology (or methodologies) for determining AFC or ATC values. The methodology (or methodologies) shall reflect the Transmission Service Provider's current practices for determining AFC or ATC values. **2.1.** Each methodology shall describe the method used to account for the following elements, provided such elements impact the determination of AFC or ATC: **2.1.1.** The simulation of transfers performed through the adjustment of generation, Load, or both; **2.1.2.** Transmission topology, including, but not limited to, additions and retirements; **2.1.3.** Expected transmission uses; **2.1.4.** Planned outages**;** **2.1.5.** Parallel path (loop flow) adjustments; **2.1.6.** Load forecast; and **2.1.7.** Generator dispatch, including, but not limited to, additions and retirements. **2.2.** Each Transmission Service Provider that uses the Flowgate Methodology shall, for reliability-related constraints identified in part 1.3, use the AFC determined by the Transmission Service Provider for that constraint.
R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall	The requirement is replaced by proposed IRO-008-2, Requirements R3, R5, and R6. **Proposed IRO-008-2, Requirement R3:**

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.	**R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, Requirement R5:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

IRO-008-1 Reliability Coordination Operational Analyses and Real-time Assessments	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.	This requirement is replaced by proposed IRO-008-2, Requirement R1. **Proposed IRO-008-2, Requirement R1:** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.
R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.	This requirement is replaced by proposed IRO-008-2, Requirement R4. **Proposed IRO-008-2, Requirement R4:** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.	This requirement is replaced by proposed IRO-008-2, Requirements R3 and R5. **Proposed IRO-008-2, Requirements R3 and R5:** **R3.** Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in that plan(s). **Proposed IRO-008-2, R6:** **R5**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: **R1.1.** List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. **R1.2.** Mutually agreeable format. **R1.3.** Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). **R1.4.** Process for data provision when automated Real-Time system operating data is unavailable.	This requirement is replaced by proposed IRO-010-2, Requirements R1 and R3. **Proposed IRO-010-2, Requirement R1:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2** Provisions for notification of current Protection System and Special Protection System status, failure, or degradation that impacts System reliability. **1.3** A periodicity for providing data. **1.4** The deadline by which the respondent is to provide the indicated data. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol
R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator.	This requirement is replaced by proposed IRO-010-2, Requirement R2. **Proposed IRO-010-2, Requirement R2:** **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard IRO-010-1a Reliability Coordinator Data Specification and Collection	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: **3.1** A mutually agreeable format **3.2** A mutually agreeable process for resolving data conflicts **3.3** A mutually agreeable security protocol

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators **R1.1** These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following: **R1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and	This requirement is replaced by proposed IRO-014-3, Requirement R1. Data is covered in proposed IRO-010-2, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Communications and notifications, and the process to follow in making those notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
information to be exchanged with other Reliability Coordinators. **R1.1.2** Energy and capacity shortages. **R1.1.3** Planned or unplanned outage information. **R1.1.4** Voltage control, including the coordination of reactive resources for voltage control. **R1.1.5** Coordination of information exchange to support reliability assessments. **R1.1.6** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	**1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas. **1.6** Provisions for weekly conference calls. **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be: **R2.1.** Agreed to by all the Reliability Coordinators required to take the indicated action(s). **R2.2**. Distributed to all Reliability Coordinators that are required to take the indicated action(s).	This requirement is replaced by proposed IRO-014-3, Requirement R2. **Proposed IRO-014-3, Requirement R2:** **R2.** Each Reliability Coordinator shall maintain its Operating Procedure, Operating Process, or Operating Plan identified in Requirement R1 as follows: **2.1** Review and update annually with no more than 15 months between reviews. **2.2** Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update. **2.3** Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update.
R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include: **R3.1.** A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	R3.1 is a strictly administrative requirement with no reliability benefit and is proposed to be retired under the P81 criteria. R3.2 is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1**: **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R3.2. The agreed-upon actions from the associated Reliability Coordinator-to- Reliability Coordinator Operating Procedure, Process, or Plan.	reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1** Criteria and processes for notifications. **1.2** Energy and capacity shortages. **1.3** Control of voltage, including the coordination of reactive resources. **1.4** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. **1.5** Provisions for periodic communications to support reliable operations.
R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall: **R4.1.** Include version control number or date. **R4.2.** Include a distribution list. **R4.3**. Be reviewed, at least once every three years, and updated if needed	This requirement is proposed to be retired as it is strictly an administrative requirement with no reliability benefit.

Standard IRO-015-1 - Notifications and Information Exchange Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators. **R1.1** The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	This requirement is replaced by proposed IRO-014-3, Requirement R1. **Proposed IRO-014-3, Requirement R1:** **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
R2. The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators. **R2.1** The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	This requirement is replaced by proposed IRO-014-3, Requirement R1, Part 1.5. **Proposed IRO-014-3, Requirement R1, Part 1.5:** **R1, Part 1.5:** Provisions for periodic communications to support reliable operations.
R3. The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	This requirement is replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …

Standard IRO-016-1 - Coordination of Real-time Activities Between Reliability Coordinators	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem. **R1.1** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken. **R1.2** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.). **R1.2.1** If time permits, this re-evaluation shall be done before taking corrective actions. **R1.2.2** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved **R1.3** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	Proposed IRO-014-3, Requirements R3 through R6 are revised versions of approved IRO-016-1, Requirement R1 and its sub-requirements. **Proposed IRO-014-3, Requirement R3:** **R3.** Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. **Proposed IRO-014-3, Requirement R4:** **R4.** Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R5:** **R5**. Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. **Proposed IRO-014-3, Requirement R6:** **R6.** Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	This retirement of this Requirement was approved by FERC effective January 21, 2014 as part of the Paragraph 81 Project.

Standard PER-001-0.2 – Operating Personnel Responsibility and Authority	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System	The SDT is proposing to retire this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the Bulk Power System have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the Bulk Power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted. FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avista, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism. The SDT does not believe that there is a need for a decision-making authority requirement as the decision-making authority is inherent in proposed TOP-001-4, Requirement R1 which states that the Transmission Operator must act or issue Operating Instructions.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R1: **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	This requirement replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed IRO-001-4, Requirements R2 and R3 and proposed TOP-001-3, Requirements R3 and R4. Proposed IRO-001-4, R2: **Proposed IRO-001-4, Requirement R2:** **R2.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-001-4, Requirement R3:** **R3.** Each Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform an Operating Instruction in accordance with Requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	This requirement replaced by proposed TOP-001-3, Requirements R3 and R4. **Proposed TOP-001-3, Requirements R3 and R4:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. Proposed TOP-001-3, R4: **R4.** Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	This requirement replaced by proposed TOP-001-3, Requirements R8, R12, and R14. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency	The Generator Operator was deleted from this requirement since it will only respond to such requests if they were in the form of an Operating Instruction from its Transmission Operator

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	or Balancing Authority which is covered in proposed TOP-001-3, Requirements R3, R4, R5 and R6. Assistance at the Transmission Operator level is provided through proposed TOP-001-3, Requirement R7. 'Emergency' deleted as the assistance is assistance in response to the other entities' emergency. Balancing Authorities provide assistance under approved EOP-001-2.1b, Requirement R1. **Approved EOP-001.2.1b, Requirement R1:** **R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities**.** **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R4:** R4. Each Balancing Authority, Generator Operator, and Distribution Provider shall inform its Transmission Operator of its inability to perform an Operating Instruction issued by that Transmission Operator in Requirement R3. **Proposed TOP-001-3, Requirement R5:** **R5.** Each Transmission Operator, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Balancing Authority, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed TOP-001-3, Requirement R6:** **R6.** Each Transmission Operator, Generator Operator, and Distribution Provider shall inform its Balancing Authority of its inability to perform an Operating Instruction issued by that Balancing Authority. **Proposed TOP-001-3, Requirement R7:**

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R7. Each Transmission Operator shall assist other Transmission Operators within its Reliability Coordinator Area, if requested and able, provided that the requesting entity has implemented its comparable Emergency procedures, unless such assistance cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: **R7.1** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.2** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. **R7.3** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and will receive this data through proposed TOP-003-3, Requirements R1 and R5 and is required to act on this information as per proposed TOP-001-3, Requirement R8. Proposed IRO-010-2, Requirements R1 and R3 handle the notifications from the Transmission Operator to the Reliability Coordinator. **Proposed TOP-001-3, Requirement R8**: **R8.** Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed IRO-010-2, Requirement R1:** **R1**. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed IRO-010-2, Requirement R3: **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications …
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – reactive power: Replaced by approved VAR-001-4, Requirement R3 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-4, Requirements R1 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-2, Requirement R1 for the Transmission Operator and Balancing Authority. **Approved EOP-002-3.1, Requirement R6:** **R6**. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Approved VAR-001-4, Requirement R3: **R3**. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **Approved IRO-009-1, Requirement R1:** **R1.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. **Approved IRO-009-1, Requirement R2:** **R2.** For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	First sentence, retained for Balancing Authority and Transmission Operator and moved to proposed TOP-002-4, Requirements R2 and R4. Second sentence – Replaced by proposed TOP-001-3, Requirements R1 and R2 for Balancing Authority and Transmission Operator, which requires action to resolve issues. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day … **Proposed TOP-001-3, Requirement R1:** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions.
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	The SDT is proposing to retire this requirement. While it may be good utility practice to do this, it is of marginal benefit to reliability and is more of a 'how' to conduct business as opposed to a definitive 'what' to do.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	The Transmission Operator and Balancing Authority will receive the necessary data in proposed TOP-003-3, Requirement R5. The Transmission Service Provider provisions are covered in approved MOD-001-1a, Requirement R1; approved MOD-030-2, Requirement R3; and approved MOD-001-1a, Requirement R2. The coordination of plans is in proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Approved MOD-001-1a, Requirement R1:** **R1.** Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. **Approved MOD-030-2, Requirement R3:** **R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that … **Approved MOD-001-1a, Requirement R2:** **R2**. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s). **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Coordination of plans is covered in proposed IRO-017-1, Requirement R2 and proposed IRO-008-2, Requirement R2. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed IRO-008-2, Requirement R2:** **R2**. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	This requirement has been moved to proposed TOP-002-4, Requirements R2 and R4. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	The part of the requirement dealing with the Balancing Authority and Transmission Operator is replaced by proposed TOP-002-4, Requirements R2 and R4. The n-1 Contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to the approved FAC standards which include Contingency planning. In addition, the definition of Operational Planning Analysis has been revised to better show the intent of the Contingency aspects of the analysis. The SDT does not believe that there is a need to replace the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **Proposed TOP-002-4, Requirement R4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch. 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed definition: Operational Planning Analysis** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	This requirement is replaced by proposed TOP-002-4, Requirement R4. **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-4, Requirement R1. Deliverability by the Balancing Authority is covered by proposed TOP-002-4, Requirement R4. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-002-4, Requirement R4:** R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	This requirement is replaced by approved INT-006-4, Requirement R5, and proposed TOP-002-4, Requirement R4. **Approved INT-006-4, Requirement R5:** **R5**. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: **Proposed TOP-002-4, Requirement R4:** **R4.** Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: **4.1** Expected generation resource commitment and dispatch. **4.2** Interchange scheduling **4.3** Demand patterns **4.4** Capacity and energy reserve requirements, including deliverability capability
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Balancing Authority - The Balancing Authority is only responsible to respond to Operating Instructions as per the definition of Balancing Authority in the NERC Glossary and, thus, consistent with the Commission-approved interpretation of Requirement R10, Balancing

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Authorities have been removed from the applicability of this requirement. SOLs and IROLs are limits which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the Bulk Power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions (as shown in proposed TOP-001-3, Requirement R3) from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. The Balancing Authority must coordinate outage information and exchange data required to allow the Transmission Operator to deal with SOLs. Those items are in proposed IRO-017-1, Requirement R2 and proposed TOP-003-3, Requirement R5. That information is considered by the Transmission Operator when formulating its Operating Plans and since IROLs are a sub-set of SOLs, this is covered in proposed TOP-002-4, requirement R2. **Proposed TOP-001-3, Requirement R3:** **R3.** Each Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications **Proposed TOP-002-4, Requirement R2:** **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	First sentence replaced by proposed TOP-002-4, Requirement R1, proposed TOP-001-3, Requirement R13. Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs. Second sentence – SOLs are set by the Transmission Operator in approved FAC-014-2, Requirement R2 according to the methodology distributed by the Reliability Coordinator in approved FAC-011-2, Requirement R4, Part 4.3. This should assure that SOLs are consistent for common facilities. Third sentence – Replaced by proposed TOP-001-3, Requirement R13 and proposed TOP-001-3, Requirement R8. **Proposed TOP-002-4, Requirement R1:** **R1**. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Approved FAC-014-2, Requirement R2:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-011-2, Requirement R4:** **R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: 4.3 Each Transmission Operator that operates in the Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Replaced by approved MOD-028-2, Requirement R6.1; approved MOD-029-1a, Requirement R3; and approved MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. **Approved MOD-028-2, Requirement R6.1:** **6.1** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: • A System Operating Limit is reached on the Transmission Service Provider's system, or • A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. **Approved MOD-029-1a, Requirement R3:** **R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. **Approved MOD-030-2, Requirement R2.4:**

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	2.4 Establish the TFC of each of the defined Flowgates as equal to: - For thermal limits, the System Operating Limit (SOL) of the Flowgate. - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	This requirement is replaced by proposed TOP-001-3, Requirement R2 where a Balancing Authority can issue Operating instructions to the Generator Operator which could include verification. The SDT believes that this requirement does not apply to the Transmission Operator since it is dealing exclusively with generation. The data coming back from the verification effort would be included in the Balancing Authority data specification as shown in proposed TOP-003-3, Requirements R2 and R5. **Proposed TOP-001-3, Requirement R2:** **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: **14.1** Changes in real and reactive output capabilities. (Retired August 1, 2007)	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
14.2 Changes in real output capabilities(Effective August 1, 2007) **14.3** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	This requirement is replaced by proposed TOP-003-3, Requirement R5. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: **16.1** - Changes in transmission facility status. **16.2** - Changes in transmission facility rating	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3**. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	This requirement replaced by proposed IRO-010-2, Requirement R3. **Proposed IRO-010-2, Requirement R3:** **R3.** Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using:
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	This requirement is proposed for retirement as it adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Accuracy is a relative term that would be difficult to objectively measure and assess compliance with. Proposed TOP-003-3, Requirement R1 stipulates that entities must supply the data needed for reliability. The expectation is that the Transmission Operator would specify the data it requires to perform its functions which would include all of the data it needs to create the model for its analyses and studies. The requirement language allows the entity to specify accuracy of the data provided as part of its data specification. This will, in turn, lead to the creation of an accurate model based on accurate data received. In addition, proposed TOP-003-3, Requirement R5, Part 5.2 allows for the resolution of any data causing conflicts that could affect the models. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R5, Part 5.2:** **5.2** A mutually agreeable process for resolving data conflicts

<table>
<tr><th colspan="2">Standard TOP-003-1 — Planned Outage Coordination</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R1. Generator Operators and Transmission Operators shall provide planned outage information.

1.1 Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

1.2 Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.

1.3 Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.</td><td>Parts 1.1, 1.2, and 1.3 are addressed as follows:

1.1 Generator Operators will provide planned outage information to Transmission Operators through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1.

1.2 Transmission Operators will provide planned outage information to Reliability Coordinators through proposed IRO-010-2, Requirement R3. Reporting requirements are set in proposed IRO-010-2, Requirement R1.

1.3 Reporting requirements are set in proposed TOP-003-3, Requirement R1 and proposed IRO-010-2, Requirement R1.

Proposed TOP-003-3, Requirement R5:
R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications …

Proposed TOP-003-3, Requirement R1:

R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification …

Proposed IRO-010-2, Requirement R3:

R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.

Proposed IRO-010-2, Requirement R1:

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td></tr>
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Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Generator Operators will provide planned outage information to Transmission Operators and Balancing Authorities through proposed TOP-003-3, Requirement R5. Reporting requirements are set in proposed TOP-003-3, Requirement R1. Transmission Operators and Balancing Authorities coordinate outages through proposed IRO-017-1, Requirement R2. **Proposed TOP-003-3, Requirement R5:** **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications … **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification … **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	This requirement is replaced by proposed TOP-001-3, Requirement R9. The data specification concept in proposed TOP-003-3 requires entities to provide data as requested. If there are outages of the equipment needed for providing that data, the entity experiencing the outage must notify the entity it is sending data to so that proper arrangements can be made for replacing the data or coming up with a plan to live without it. It is expected that the data specifications would incorporate such concepts. **Proposed TOP-001-3, Requirement R9:** **R9**. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and known impacted interconnected entities of all planned outages, and unplanned outages of 30 minutes or more, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities.

Standard TOP-003-1 — Planned Outage Coordination	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	This requirement is replaced by proposed IRO-008-2, Requirement R2 and proposed IRO-017-1, Requirement R1, Part 1.4. **Proposed IRO-017-1, Requirement R1, Part 1.4**: **1.4** Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators **Proposed IRO-008-2, Requirement R2:** **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	This requirement has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14**. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The SDT has revised the definitions of Operational Planning Analysis and Real-time Assessment to address all Contingencies, not just the single most severe Contingency and operations follow suit as shown in proposed TOP-001-3, Requirement R14 and proposed TOP-002-4, Requirement R2.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-002-4, Requirement R2:** **R2**. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	This requirement is replaced by proposed TOP-001-3, Requirements R12 and R14. These requirements are not limited by single or multiple Contingencies. Approved FAC-011-2 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. Approved FAC-014-2, Requirement R6 requires the Planning Coordinator to identify the subset of multiple Contingencies and to provide this list to the Reliability

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Coordinators. Approved FAC-011-2, Requirement R3.3 requires the Reliability Coordinator to include in its SOL methodology a process for determining which of the Stability limits associated with multiple Contingencies are used to establish SOLs. Approved FAC-014-2, Requirement R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. Approved FAC-014-2, Requirement R1 also requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area while approved FAC-014-2, Requirement R2 also requires the Transmission Operator to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Approved FAC-011-2, Requirement R1:** **R1**. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: **R1.1**. Be applicable for developing SOLs used in the planning horizon **R1.2.** State that SOLs shall not exceed associated Facility Ratings. **R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs. **Approved FAC-011-2, Requirement R3:** **R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: **R3.3**. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. **R3.3.1**. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. **Approved FAC-014-2, Requirement R1:** **R1.**The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. **Approved FAC-014-2, Requirement R2:** **R2.** The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. **Approved FAC-014-2, Requirement R6:** **R6.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. **R6.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. **R6.2.** If the Planning Authority does not identify any stability related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.
R4. If a Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	The SDT believes that given the revised definitions for Operational Planning Analysis and Real-time Assessment, as well as the new requirement for TOPs to update their OPA results through the performance of a Real-time Assessment every 30 minutes, that entities will always be operating to valid operating limits. Therefore, this requirement is replaced by proposed TOP-001-3, Requirements R12, R13, and R14 along with the revised definitions of Operational Planning Analysis and Real-time Assessment. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the Bulk Power System.

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-001-3, Requirement R12: **R12**. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. P**roposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition:** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is proposed for retirement by the SDT. In the Functional Model v5, the

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
Operator may take such actions, as it deems necessary, to protect its area.	Transmission Operator responsibilities and duties are clearly spelled out. Item 14 states that a Transmission Operator sheds load under the auspices of the Reliability Coordinator. Functional model v5: 14. Coordinates load shedding with, or as directed by, the Reliability Coordinator
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: **6.1** Monitoring and controlling voltage levels and real and reactive power flows. **6.2** Switching transmission elements. **6.3** Planned outages of transmission elements. **6.4** Responding to IROL and SOL violations.	The first sentence has been superseded by the NERC Reliability Standards taken as a whole and is proposed to be retired. The second sentence was replaced as follows: **R6.1** is duplicative of approved VAR-001-4, Requirement R1 for reactive power. Real power flows are covered in proposed TOP-001-3, Requirements R10, R12 and R14. **R6.2** has been replaced by proposed TOP-001-3, Requirement R8. **R6.3** has been replaced by proposed IRO-017-1, Requirement R2. **R6.4** has been replaced by proposed TOP-001-3, Requirements R12 and R14. **Approved VAR-001-4, Requirement R1:** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

Standard TOP-004-2 — Transmission Operations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-017-1, Requirement R2:** **R2.** Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Standard TOP-005-2a — Operational Reliability Information	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Recognizing security concerns, the SDT has added security protocols to proposed IRO-010-2, Requirement R3, Part 3.3 and to proposed TOP-003-3, Requirement R5, Part 5.3 to address overall security concerns. **Proposed IRO-010-2, Requirement R3, Part 3.3:** **3.3** A mutually agreeable security protocol **Proposed TOP-003-3, Requirement R5, Part 5.3:** **5.3** A mutually agreeable security protocol.
R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-2a "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	This requirement replaced by proposed TOP-003-3, Requirement R1, R2, and R5. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed TOP-003-3, Requirement R5:** **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.
R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted as redundant to NAESB standards – All operating data that a Purchasing-Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

<table>
<tr><th colspan="2">Standard TOP-006-3 – Monitoring System Conditions</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Proposed Language in New Standard or Comment</th></tr>
<tr><td>R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

1.2 - Each Transmission Operator shall inform the Reliability Coordinator and other affected Transmission Operators of all transmission resources available for use.

1.3 - Each Balancing Authority shall inform its Reliability Coordinator of all generation resources available for use.</td><td>The main body of the requirement is replaced by proposed TOP-001-3, Requirements R10 and R11.
1.1 This Part is replaced by proposed TOP-003-3, Requirement R5.
1.2 This Part is replaced by proposed IRO-101-2, Requirement R3.
1.3 This Part is replaced by proposed IRO-010-2, Requirement R3.

Proposed TOP-001-3, Requirement R10:
R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

Proposed TOP-001-3, Requirement R11:
R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Proposed TOP-003-3, Requirement R5:
R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications.

Proposed IRO-010-2, Requirement R3:
R3. Each Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications.</td></tr>
</table>

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	This requirement is replaced by proposed IRO-002-4, Requirement R3, proposed TOP-001-3, Requirement R10, and proposed TOP-001-3, R11. The requirements mandate that any Facility needed for an entity to perform its reliability-based functions must be monitored. This would include load-tap changers, rotating and static reactive resources, etc. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.**1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide its operating personnel with appropriate technical information concerning protective relays within the Reliability Coordinator Area, the Transmission Operator Area, and the Balancing Authority Area, respectively.	This requirement replaced by proposed IRO-010-2, Requirement R1, Part 1.2; proposed TOP-003-3, Requirement R1, Part 1.2; and proposed TOP-003-3, Requirement R2, Part 2.2.; and the proposed changes to the definitions of Operational Planning Analysis and Real-time Assessment.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed definition: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed IRO-010-2, Requirement R1, Part 1.2:** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **Proposed TOP-003-3, Requirement R1, Part 1.2:** **R 1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	Proposed TOP-003-3, Requirement R2, Part 2.2: **R2**. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	This requirement replaced by proposed TOP-003-3, Requirement R1 and R2 with regard to load patterns. Weather forecasts are a necessary element for load forecasts which are required for Operational Planning Analysis. Therefore, this requirement can be retired. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-003-3, Requirement R2:** **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. **Proposed definition:** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	This requirement replaced by proposed TOP-001-3, Requirements R10 and R11, and proposed IRO-002-4, Requirement R3. **Proposed TOP-001-3, Requirement R10:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **Proposed IRO-002-4, Requirement R3:** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	The requirement is replaced by proposed TOP-003-3, Requirements R1 and R2 which state that data specifications can include, but are not limited to the 4 criteria listed. This allows for an entity to create specifications that would include items such as range of metering, accuracy, etc. **Proposed TOP-003-3, Requirement R1:** **R1**. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **Proposed TOP-003-3, Requirement R2:**

Standard TOP-006-3 – Monitoring System Conditions	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R2. Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to:
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	This requirement is replaced by proposed IRO-002-4, Requirement R3, and proposed TOP-001-3, Requirements R10 and R11. **Proposed IRO-002-4, Requirement R3**: **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3, Requirement R10:** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: 10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and 10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **Proposed TOP-001-3, Requirement R11:** **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	This requirement is replaced by proposed TOP-001-3, Requirement R15. The Reliability Coordinator has the primary responsibility for IROLs and will be in communication with Transmission Operators to mitigate the situation. This is shown in proposed IRO-008-2, Requirements R5 and R6. **Proposed TOP-001-3, Requirement R15:** **R15.** Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded. **Proposed IRO-008-2, Requirement R5:** **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed IRO-008-2, Requirement R6:** **R6.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	This requirement is replaced by proposed TOP-001-3, Requirement R12 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4.** When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Proposed TOP-001-3, Requirement R12:**

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
	R12. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	This requirement replaced by approved EOP-003-2, Requirement R1 and approved IRO-009-1, Requirement R4. **Approved IRO-009-1, Requirement R4:** **R4**. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. **Approved EOP-003-2, Requirement R1:** **R1**. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	This requirement replaced by proposed IRO-008-2, Requirement R6. **Proposed IRO-008-2, Requirement R6:** **R6**. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	This requirement replaced by approved EOP-003-1, Requirement R1 and proposed TOP-001-3, Requirements R12 and R14. **Approved EOP-003-2, Requirement R1:** **R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	First sentence – Replaced by proposed TOP-001-3, Requirements R12 and R14. Second sentence – Replaced by proposed TOP-001-3, Requirement R18. **Proposed TOP-001-3, Requirement R12:** **R12.** Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. **Proposed TOP-001-3, Requirement R14:** **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed TOP-001-3, Requirement R18:** **R18**. Each Transmission Operator shall operate to the most limiting parameter in instances where there is a difference in SOLs.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall	First sentence - Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with

Standard TOP-008-1 - Response to Transmission Limit Violations	
Requirement in Approved Standard	**Proposed Language in New Standard or Comment**
notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	other functional entities. Such actions, taken unilaterally, could make conditions worse. Therefore, the SDT is proposing to retire this requirement. Second sentence – In general, notification is replaced by proposed TOP-001-3, Requirement R8. **Proposed TOP-001-3, Requirement R8:** **R8**. Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	The part of the requirement dealing with data is replaced by proposed TOP-003-3, Requirement R1. The part of the requirement dealing with analysis is replaced by proposed TOP-002-4, Requirement R1 and proposed TOP-001-3, Requirement R13. **Proposed TOP-003-3, Requirement R1:** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **Proposed TOP-002-4, Requirement R1:** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **Proposed TOP-001-3, Requirement R13:** **R13**. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

4. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.

2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.

3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

<u>Facility Rating Exceedance</u>

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

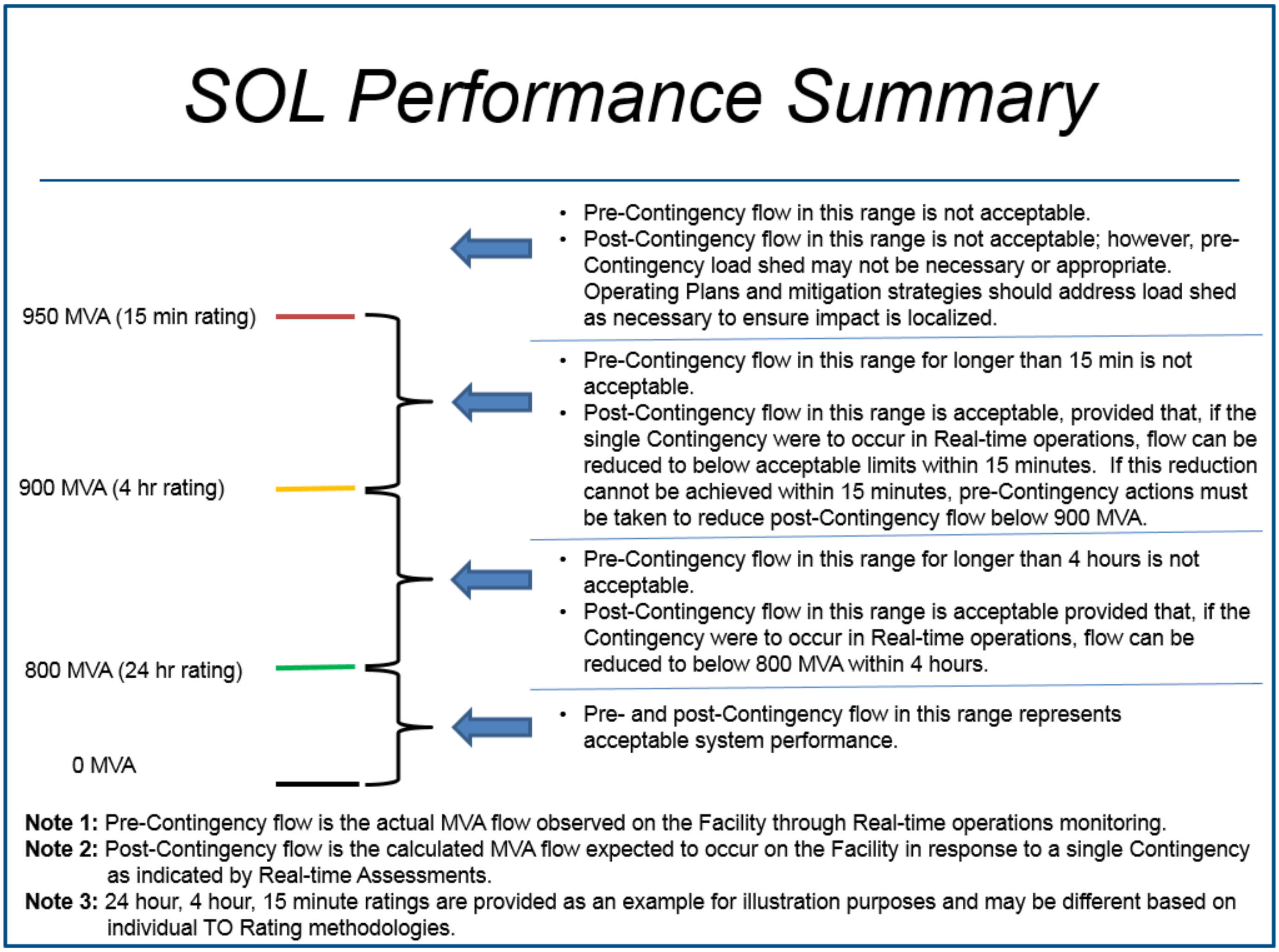

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

Steady State Voltage Limit Exceedance

SOL performance for steady state voltage limits is determined through Real-time Assessments. Normal and emergency voltage limits are expected to respect any voltage limitations specified in the Transmission

Owner's or the Generation Owner's Facility Ratings Methodology per approved FAC-008-3. Normal voltage limits are typically applicable for the pre-Contingency state while emergency voltage limits are applicable for the post-Contingency state. SOL exceedance with respect to these voltage limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments should recognize the impact of auto-reactive devices and whether or not those devices are sufficient for maintaining voltages within acceptable limits pre- or post-Contingency.

Stability Limit Exceedance

Transient and voltage Stability limits can be determined through prior studies, or they can be determined in Real-time.

Transient Stability limits are often expressed as flow limits on a defined interface or cut plane that, if operated within, ensures that the system will remain transiently stable should the identified Contingency(s) occur. Transient instability could take several forms, including undamped oscillations, or angular instability resulting in portions of the system losing synchronism.

Though voltage Stability limits can be determined, expressed, and monitored in several ways, the general principle is universal – voltage Stability limits are intended to ensure that the system does not experience voltage collapse in the pre- or post-Contingency state.

SOL exceedance for Stability limits occurs when the system enters into an operating state where the next Contingency could result in transient or voltage instability. Figure 2 depicts a wide-area voltage Stability based SOL that qualifies as an IROL. In this example, SOL (IROL) exceedance occurs when power transfers over the monitored Facility(s) exceeds the P_{IROL} value. Note - A localized voltage collapse may not qualify as an IROL.

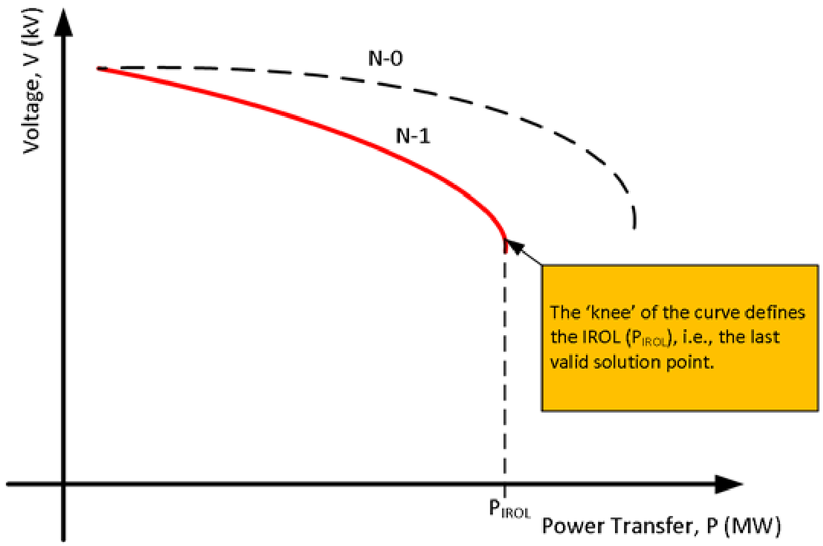

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

- Actual flow on a Facility is above the Facility Rating for an unacceptable time duration
- Calculated Post-Contingency flow on a Facility is above the highest available Facility Rating
- Actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits
- Post-Contingency bus voltage is outside acceptable post-Contingency (emergency) bus voltage limits
- Defined transient or voltage Stability limits are exceeded (techniques for determining and observing Stability limits can vary)

SOL Exceedance and Operating Plans:

When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

Contingency. Post-Contingency mitigation plans/strategies are actions that are implemented after the Contingency occurs to bring the system back within limits. Operating Plans contain details to include appropriate timelines to escalate the level of mitigating plans/strategies to ensure BES performance is maintained as per approved FAC-011-2, Requirement R2, preventing SOL exceedances from becoming an IROL. Operating Plan(s) must include the appropriate time element to return the system to within acceptable Normal and Emergency (short-term) Ratings and/or operating limits identified above. For example, in Figure 1, operating above the 950 MVA 15 minute limit would be an SOL exceedance for actual flows and may also be an exceedance for projected post-Contingency flows if a communicated post-Contingency load shed plan cannot be implemented in a timely fashion in order to prevent post-Contingency equipment damage and/or non-localized Cascading outages. However, operating between 900 MVA and 950 MVA is not an SOL exceedance unless the associated Operating Plan time parameter is exceeded as explained in Figure 1.

An example Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	**Pre-Contingency (actual) Loading**	**Post-Contingency (calculated) Loading**
Normal (24 hr)	**Reconfiguration actions, Redispatch actions, emergency procedures except Load shed consistent with timelines identified in Operating Plan.**	**Trend – continue to monitor. Take reconfiguration actions to prevent Contingency from exceeding emergency limit consistent with timelines identified in Operating Plan.**
Emergency (4 hr)	**All of the above plus Load shed only if necessary and appropriate to control loading below 4 hr Emergency Rating consistent with timelines identified in Operating Plan.**	**Use available effective actions and emergency procedures except Load shed consistent with timelines identified in Operating Plan.**
Emergency (15 min)	**All of the above plus Load shed to control loading below 15 min Emergency Rating consistent with timelines identified in Operating Plan.**	**All of the above however, Load shed only if necessary and appropriate to avoid post-Contingency Cascading consistent with timelines identified in Operating Plan.**

Table 1. Operating Plan Example

APPLICABLE DEFINITIONS

Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Operational Planning Analysis – An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Changes made to the definitions of Real-time Assessment and Operational Planning Analysis were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments and Operational Planning Analysis contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

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Time Horizons

When establishing a time horizon for each requirement, the following criteria should be used:

- **Long-term Planning –** a planning horizon of one year or longer.
- **Operations Planning** – operating and resource plans from day-ahead up to and including seasonal.
- **Same-Day Operations** – routine actions required within the timeframe of a day, but not Real-time.
- **Real-time Operations** – actions required within one hour or less to preserve the reliability of the Bulk Electric System.

Facility Rating – The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Normal Rating – The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating – The rating as defined by the equipment owner that specifics the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar, or other appropriate units, that a system, facility, or element can support, procedure, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

System Operating Limit Definition and Exceedance Clarification

The NERC-defined term System Operating Limit (SOL) is used extensively in the NERC Reliability Standards; however, there is much confusion with – and many widely varied interpretations and applications of – the SOL term. This whitepaper describes the Standard Drafting Team's (SDT) intent with regard to the SOL concept and brings clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances.

System Operating Limit Definition Clarification:
As stated in the NERC Glossary of Terms Used in Reliability Standards, a SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post- Contingency equipment or Facility ratings)
- Transient Stability Ratings (Applicable pre- and/or post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and/or post- Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

The concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2, and FAC-014-2:

1. The purpose of approved FAC-008-3, which is applicable to both Generation and Transmission Owners, is to ensure that Facility Ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of SOLs. The standard requires both Generation Owners and Transmission Owners to have a documented Facility Rating that respects the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility. The scope of the Ratings addressed shall include, as a minimum, both Normal and Emergency (short-term) Ratings (approved FAC-008-3, Requirement R3, part 3.4.2). A 24-hour continuous rating is an example of a Normal rating; however, rating practices vary from entity to entity and may include ratings that vary with ambient temperature. Typical Emergency (short-term) Ratings have a finite duration of less than 24 hours (e.g., 4 hours, 2 hours, 1 hour, 30 minutes, or 15 minutes).

2. The purpose of approved FAC-011-2, which is applicable to Reliability Coordinators, is to ensure that SOLs used in the reliable operation of the BES are determined based on an established methodology or methodologies. Approved FAC-011-2, Requirement R2 requires that the Reliability Coordinator's SOL Methodology include a requirement that SOLs provide a certain level of BES performance for the pre- and post-Contingency state. Specifically:

   Pre-Contingency: Acceptable system performance for the pre-Contingency state is characterized by the following:

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their pre-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.

   Post-Contingency: Acceptable system performance for the post-Contingency state for single Contingencies is characterized by the following (approved Reliability Standard FAC-011-2, Requirement R2, part 2.2):

   a. The BES shall demonstrate transient, dynamic, and voltage Stability.
   b. All Facilities shall be within their applicable Facility Ratings and thermal limits.
   c. All Facilities shall be within their post-Contingency voltage limits.
   d. All Facilities shall be within their Stability limits.
   e. Cascading or uncontrolled separation shall not occur.

3. Approved FAC-011-2 Requirement R3, Part 3.1 also ensures that the Reliability Coordinator's methodology for determining SOLs includes a description of the study model, which at a minimum must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study as well as the level of detail of system models used to determine SOLs which is shown in approved FAC-011-2, Requirement R3, Part 3.4. The requirements within approved FAC-011-2, when combined with the BES Exception Process which is designed to bring impactful facilities into the BES, ensure that all facilities that can adversely impact BES reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies.

4. Approved FAC-014-2, Requirement R2 requires that Transmission Operators establish SOLs for their portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Some have interpreted the language in approved FAC-011-2, Requirement R2 to imply that the objective is to perform prior studies to determine a specific MW flow value (SOL) that ensures operation within the criteria specified in approved FAC-011-2, Requirement R2 sub-requirements, the assumption being that if the system is operated within this pre-determined SOL value, then all of the pre- and post-Contingency requirements described in approved FAC-011-2, Requirement R2 will be met. The SDT believes this approach may not capture the complete intent of the SOL concept within approved FAC-011-2, which is both:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

SOLs are based on Normal and Emergency (short-term) Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits – any of which can be the most restrictive limit at any point in time pre- or post-Contingency. For example, if an area of the BES is at no risk of encroaching upon Stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the voltage limits in that area are the most limiting SOLs.

It is important to distinguish operating practices and strategies from the SOL itself. As stated earlier, the SOL is based on the actual set of Facility Ratings, voltage limits, or Stability limits that are to be monitored for the pre- and post-Contingency state. How an entity remains within these SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by that entity. For example, one Transmission Operator may utilize line outage distribution factors or other similar calculations as a mechanism to ensure SOLs are not exceeded, while another may utilize advanced network applications to achieve the same reliability objective.

In order to ensure an SOL is not exceeded, the following SOL performance must be maintained:

1. **Facility Ratings:**
   In the pre- and post-Contingency state, operate within Facility capability by utilizing Normal and Emergency (short-term) Ratings, as applicable, within their associated time parameters.
2. **Voltage Limits:**
   In the pre-Contingency state, operate within normal voltage limits. In the post-Contingency state, operate within applicable emergency voltage limits.
3. **Transient Stability Limits:**
   Transmission Operators establish SOLs to prevent intra-area instability, inter-area instability, or tripping of Facilities due to out-of-step conditions. Transient Stability limits are typically defined as the maximum power transfer or load level that ensures critical transient reliability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.
4. **Voltage Stability Limits:**
   Transmission Operators typically stress Transmission Paths/Interfaces or load areas to the reasonably expected maximum transfer conditions or area load levels to determine whether steady state voltage Stability limits exist. Voltage Stability limits are typically defined as the maximum power transfer or load level that ensures voltage Stability criteria are met. Calculated flows must be maintained within appropriate pre- and/or post-Contingency limits.

System Operating Limit Exceedance Clarification:

The combination of requirements contained within the approved FAC and proposed TOP standards, as well as the use of defined terms contained within those standards such as Operational Planning Analysis, Real-time Assessment, and Operating Plans when executed properly result in maintaining reliable BES performance. Specifically,

1. Approved FAC standards require clear determination of Facility Ratings and describe acceptable system performance criteria for the pre- and post-Contingency state.
2. Proposed TOP-001-3, Requirement R13 requires that a Transmission Operator perform a Real-time Assessment at least once every 30 minutes.
3. Proposed TOP-002-4, Requirement R2 requires that each Transmission Operator have an Operating Plan to address potential SOL exceedances identified as a result of its Operational Planning Analysis.
4. Proposed TOP-001-3, Requirement R14 requires the Transmission Operator to initiate Operating Plan(s) to mitigate SOL exceedances.

Facility Rating Exceedance

Facility Rating exceedance is a function of the available limit set and the magnitude of pre- or post-Contingency flows in relation to those limits as observed in Real-time monitoring or Real-time Assessments. Figure 1 illustrates an SOL Performance Summary for Facility Ratings.

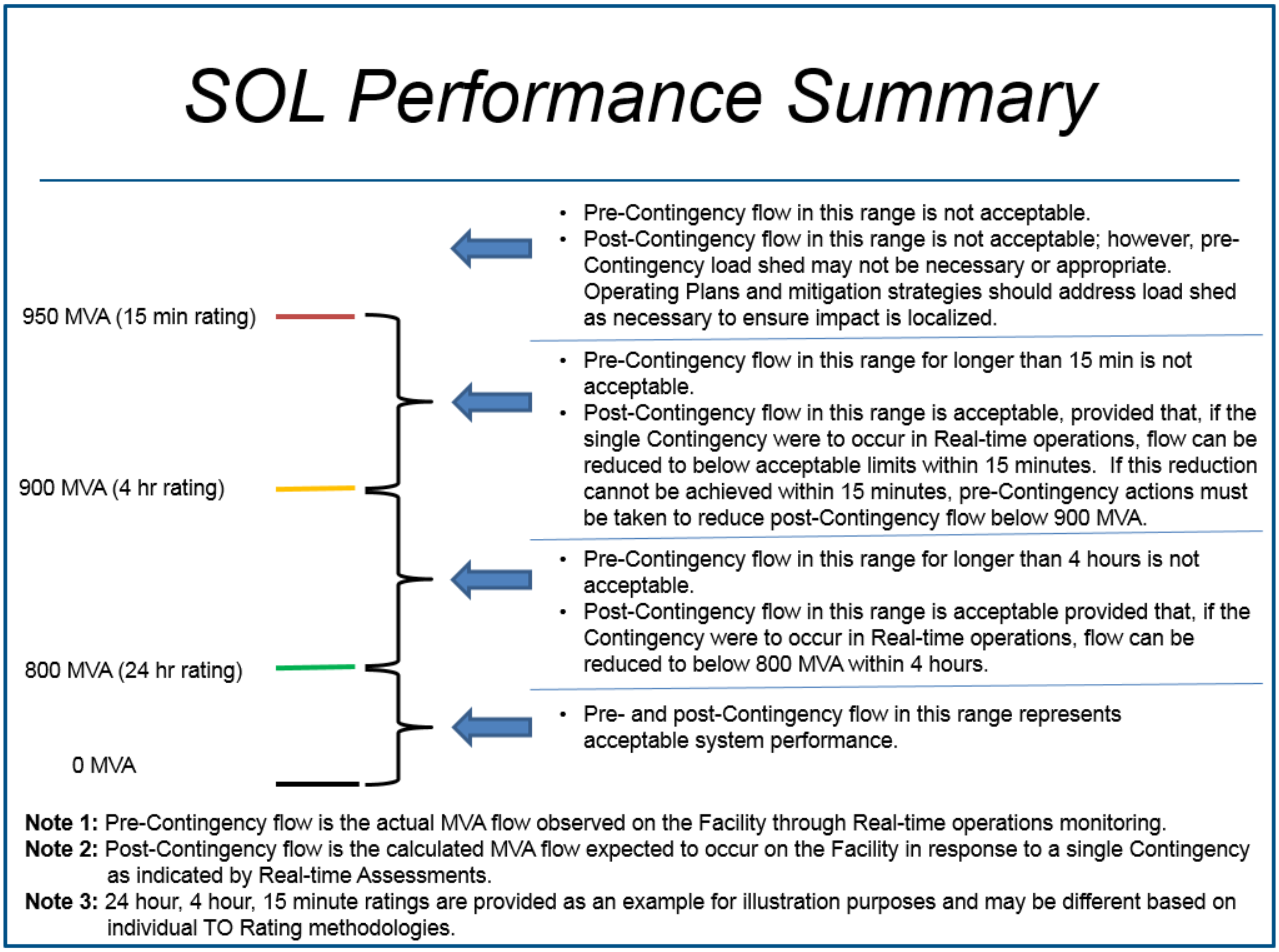

Figure 1. Facility Rating System Operating Limit Performance Summary

In cases where post-Contingency flow exceeds the highest available Facility Rating as shown in Figure 1, Transmission Operators are expected to take pre-Contingency action to relieve the condition (including redispatch, reconfiguration, and making adjustments to the uses of the transmission system); however, the operating condition may not warrant shedding load pre-Contingency to relieve the condition. Pre-Contingency Load shed is generally utilized as a last resort in conditions where the next Contingency could result in Cascading or widespread instability. An entity's Operating Plan is expected to define when it is appropriate to shed Load pre-Contingency versus post-Contingency while ensuring the BES remains N-1 secure.

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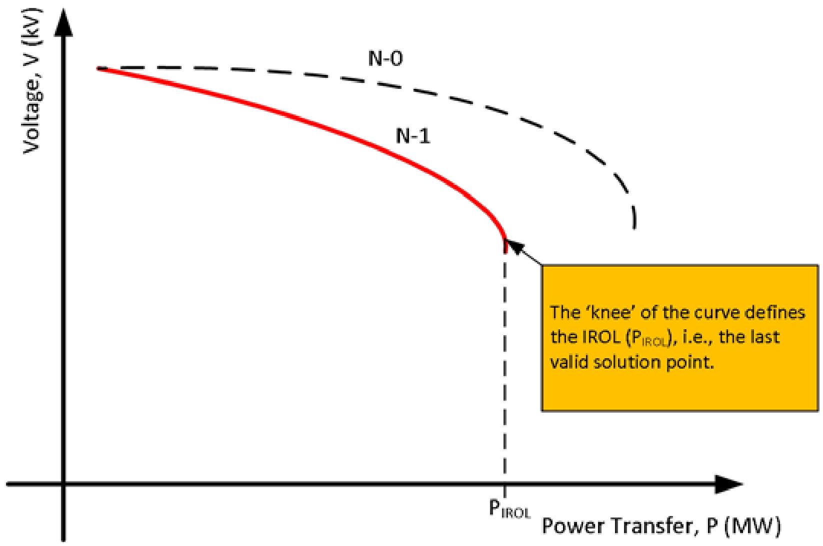

Figure 2. Voltage Stability System Operating Limit Performance Summary

SOL exceedance occurs when acceptable system performance as described in approved FAC-011-2 is not occurring in Real-time operations as determined by Real-time Assessments. In other words, unacceptable system performance as indicated by Real-time Assessments equates to SOL exceedance. An SOL is exceeded when any of the following occur or are observed as part of a Real-time Assessment:

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When an SOL is being exceeded in Real-time operations, the Transmission Operator is required to implement mitigating strategies consistent with its Operating Plan(s). Operating Plans can include specific Operating Procedures or more general Operating Processes. Operating Plans include both pre- and post-Contingency mitigation plans/strategies. Pre-Contingency mitigation plans/strategies are actions that are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the

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An example Operating Plan is shown in Table 1.

Thermal SOL Limit Exceeded	Pre-Contingency (actual) Loading	Post-Contingency (calculated) Loading
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Real-time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

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<u>TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)</u>

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

<u>Plan and Operate within all System Operating Limits</u>

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

<u>SDT Consideration:</u>

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R2, R5, and R6 have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R3.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

SDT consideration:

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

> Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.
>
> Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
>
> Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.
>
> Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.
>
> Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance.

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs.

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

Proposed TOP-001-3, Requirement R11: Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

SDT consideration:

See previous response.

Compliance with Reliability Directives

Para 64: The currently-effective TOP Reliability Standards use “reliability directive,” which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of “Reliability Directive” appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

SDT consideration:

The Project 2014-03 SDT is replacing the term ‘reliability directive’ with the defined term ‘Operating Instruction’ throughout the proposed standards. The proposal to use a new defined term ‘Reliability Directive’ is no longer being considered.

Para 65: NERC’s TOP and IRO petitions do not explain the proposed, defined term “Reliability Directive,” or why compliance with a transmission operator’s directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time

Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs. This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
>
> Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.
>
> Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

<u>SDT consideration:</u>

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term “projected System conditions” in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

<u>SDT consideration:</u>

See previous responses under this heading.

<u>Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States</u>

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator “shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.” NERC’s Petition does not provide an explanation for the deletion. However, the NERC “mapping document,” which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

<u>SDT consideration</u>:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.

> Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
>
> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An

> Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

SDT consideration:

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying ‘cause’ for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

<u>SDT consideration:</u>

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

<u>SDT consideration:</u>

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
> 2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

> Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

> Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs

that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is 'what' must be accomplished but doesn't explain 'how' it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission

outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that “unknown states” cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

SDT consideration:

See response to paragraph 73 above.

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers the situation where backup or redundant capabilities are required.

> Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2’s requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC’s proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

> Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-3, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

Proposed IRO-014-3, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for

generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
1.1 Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
1.2 Specify outage submission timing requirements.
1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: A mutually agreeable security protocol.

Proposed IRO-010-2, Requirement R3, Part 3.3: A mutually agreeable security protocol.

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, non-BES data, and applicable relay data are included.

Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

<u>TOP/IRO Standards - Items for SDT Discussion from FERC NOPR (*Updated August 2014*)</u>

Monitoring System Conditions - Transmission Operations Reliability Standard
Transmission Operations Reliability Standards
Interconnection Reliability Operations and Coordination Reliability Standards
145 FERC ¶ 61,158 (2014)

<u>Plan and Operate within all System Operating Limits</u>

Para 42: Without a requirement to analyze and operate within all SOLs in the proposed standards and by limiting non-IROL SOLs to only those identified by the transmission operator internal to its area, system reliability is reduced and negative consequences can occur outside of the transmission operator's internal area.

Para 43: … affects at least proposed Reliability Standard TOP-002-3, Requirements R1 and R2 as well as proposed Reliability Standard TOP-001-2, Requirements R8 through R11

<u>SDT Consideration:</u>

The Project 2014-03 SDT has changed the proposed requirements to include all SOLs. This resolves the first issue (analyze and operate within all SOLs) identified in paragraph 42. See proposed TOP-001-3, Requirements R14 and R15.

Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Proposed TOP-001-3, Requirement R15: Each Transmission Operator shall inform its Reliability Coordinator of actions taken to return the System to within limits when a SOL has been exceeded.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R4, Part 4.3 requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. In addition, proposed IRO-008-2, Requirements R1, R~~3~~<u>2</u>, R~~6~~<u>5</u>, ~~R7,~~ and R~~8~~<u>6</u> have been revised to include System Operating Limits. This resolves the second issue (only those identified… internal to its area) in paragraph 42.

Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.) Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Proposed IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

Proposed IRO-008-2, Requirement R2: ~~Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1 considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.~~ Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

~~Proposed IRO-008-2, Requirement R4: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Reliability Coordinator Wide Area.~~

Proposed IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.

Proposed IRO-008-2, Requirement R6: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.

A remaining issue would be where SOLs overlap Transmission Operator Areas as pointed out in the Technical Conferences. If the SOL overlaps Transmission Operator Areas, then the Transmission Operator would coordinate with its Reliability Coordinator with its wide-area view to cover that SOL. This topic is already covered by the SOL methodology defined in approved FAC-011-2, Requirement R1, and the requirement to coordinate operations between Reliability Coordinators as shown in proposed IRO-014-3, Requirement R1. See also proposed IRO-002-4, Requirement R43.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Proposed IRO-014-3, Requirement R1: Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

Para 52: During deteriorating system conditions, an SOL can rapidly degrade into an IROL. … NERC has not explained adequately why the only "true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue." Major cascading events including the Northeast Blackout of 2003 and the 2011 Southwest Outage were initiated by a non-IROL SOL exceedance, followed by a series of non-IROL SOL exceedances until the system cascaded.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 53: We recognize that, if IROLs and non-IROL SOLs are determined accurately, the reliability consequences of an exceedance should usually be greater for the former than the latter. If NERC or commenters believe this probability warrants general exclusion of the latter from the TOP Reliability Standards (subject to an entity's specific inclusions), they should explain this view in more detail and present any information that may help us weigh its merit.

SDT consideration:

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

Para 54: We believe that the transmission operator should have operational or mitigation plans for all Bulk-Power System IROLs and SOLs that can be implemented within 30 minutes or less to return the system to a secure state.

SDT consideration:

The original project teams (Projects 2006-06 and 2007-03) established the concept of operating within IROL T_v. T_v is always less than or equal to 30 minutes so the issue for IROLs is covered.

The Project 2014-03 SDT has agreed to the addition of all SOLs as explained above (see paragraph 43 response). Requirements for handling SOLs within a specified timeframe are covered under approved FAC-008-3, Requirement R6 where each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. These Facility Ratings are part of the data required in the data specifications mandated in proposed TOP-003-3, Requirement R1. The Project 2014-03 SDT agrees the Transmission Operator shall have operational or mitigation plans for all SOLs that consider time-based rating methodology. See proposed TOP-001-3, Requirement R14. The SDT agrees that the Transmission Operator shall develop and coordinate these mitigation plans with its Reliability Coordinator – see proposed TOP-002-4, Requirement R6. Such plans shall also include steps that ensure BES performance consistent with approved FAC-011-2 Requirement R2, including provisions for pre-Contingency load shed to avoid voltage instability, uncontrolled Cascading, or separation.

Approved FAC-008-3, Requirement R6: Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings.

Proposed TOP-003-3, Requirement R1: Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Proposed TOP-001-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.

Proposed TOP-002-4, Requirement R6: Each Transmission Operator shall provide its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator.

Approved FAC-011-2, Requirement R2: The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance.

Para 55: Because proposed Reliability Standard TOP-001-2, Requirement R8 requires a transmission operator's notification of only those SOLs identified in a next-day Operational Planning Analysis, the Commission believes it is possible for additional SOLs to develop or occur in the same-day or real-time operational time horizon. This could impose an operational risk to the interconnected transmission network. For example, if real-time system load levels are unexpectedly higher than forecasted load conditions used in the Operational Planning Analysis, this condition could result in real-time SOLs not identified in the Operational Planning Analysis because facility ratings and stability limits are now exceeded under high load levels whereas under the forecasted load levels (lower load levels), facility ratings and stability limits were not expected to be exceeded. … we believe that the Requirement R8 operational responsibilities and actions should pertain to all IROLs and all SOLs for all operating time horizons.

SDT consideration:

The Project 2014-03 SDT views the time horizon item as an issue that involves analysis tools in a Real-time environment. The intent of the original SDTs was that any aspect of analysis tools would be covered in Project 2009-02. For various reasons, that project has been delayed. Therefore the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 to the SOL and Transmission Operator Area – see proposed TOP-001-3, Requirement R13. In addition, the SDT has added proposed TOP-001-3, Requirement R16 concerning operator control of monitoring and analysis capability outages.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> Proposed TOP-001-3, Requirement R16: Each Transmission Operator shall provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities

As part of this process, the definition of Real-time Assessment has been revised to provide greater clarity as to the intent of the defined term.

> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

The Project 2014-03 SDT believes that approved EOP-008-1, Requirement R1, Part 1.6.2 assures that any solution to the analysis issue in the preceding paragraphs is adequately covered as to redundancy and back-up concerns.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

In addition, due to concerns raised in the Technical Conferences, the Project 2014-03 SDT has provided guidance as to when an entity has exceeded a limit. This guidance is provided in a white paper that will be shown in the Associated Documents (Section F) of proposed TOP-001-3.

Para 56: Specifically, we propose to direct that NERC develop modifications to Reliability Standard TOP-002-3, Requirements R1 and R2 that address our concerns discussed above to ensure that transmission operators develop mitigation plans for all IROLs and SOLs expected to be exceeded. Similarly, for proposed Reliability Standard TOP-001-2, Requirement R8, we propose to direct that NERC develop modifications to require that transmission operator actions apply to all SOLs identified in all operational time horizons (operations planning, same-day operations and real-time operations). Further, for proposed Reliability Standard TOP-001-2, Requirements R9 through R11, we propose to direct that NERC develop modifications to require that transmission operator specified actions apply to all SOLs related responsibilities in the real-time operations time horizon.

SDT consideration:

See responses above to previous cited paragraphs on SOLs.

System Models, Monitoring and Tools

Para 60: Monitoring and analysis capabilities are essential in establishing and maintaining situational awareness. While NERC indicates that these functions are assured through the certification process, we are not convinced that NERC's certification process is a suitable substitute for a mandatory Reliability Standard. … certification is a one-time process that may not adequately assure continual operational responsibility would occur if these requirements were in a Reliability Standard.

SDT consideration:

With respect to monitoring, the Project 2014-03 SDT has adapted approved IRO-003-2, Requirement R1 for the Transmission Operator and Balancing Authority Areas. See proposed TOP-001-3, Requirements R10 & R11.

Proposed TOP-001-3, Requirement R10: Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:

10.1 Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems and

10.2 Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.

Proposed TOP-001-3, Requirement R11: ~~Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order for it to be able to perform its reliability functions.~~ Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

With respect to analysis, the Project 2014-03 SDT has adapted approved IRO-008-1, Requirement R2 for the Transmission Operator. See proposed TOP-001-3, Requirement R13.

Proposed TOP-001-3, Requirement R13: ~~Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.~~ Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Para 61: The retirement of the current IRO and TOP requirements that address monitoring and analysis capabilities should not occur until the completion and implementation of Project 2009-02. Thus, in its NOPR comments NERC should propose a schedule that it will follow to ensure it completes and implements Project 2009-02 prior to any retirement of the standard such that there would be no gap.

SDT consideration:

See previous response.

Compliance with Reliability Directives

Para 64: The currently-effective TOP Reliability Standards use "reliability directive," which, as an undefined term, does not appear to be limited to a specific set of circumstances. … In contrast, application of the proposed definition of "Reliability Directive" appears to require compliance with transmission operator directives only in emergencies, not normal or pre-emergency times. … We believe that directives from a reliability coordinator or transmission operator should be mandatory at all times, and not just during emergencies (unless contrary to safety, equipment, regulatory or statutory requirements).

SDT consideration:

The Project 2014-03 SDT is replacing the term 'reliability directive' with the defined term 'Operating Instruction' throughout the proposed standards. The proposal to use a new defined term 'Reliability Directive' is no longer being considered.

Para 65: NERC's TOP and IRO petitions do not explain the proposed, defined term "Reliability Directive," or why compliance with a transmission operator's directives should be required only during emergencies (if this is the intent). Accordingly, we seek from NERC and other interested entities clarification and technical explanation regarding the scope and intent of the defined term, as well as the anticipated reliability benefits and/or drawbacks of the proposed term.

SDT consideration:

See previous response for paragraph 64.

Para 66: … NERC has not explained or justified its request for approval of the revised definition.

SDT consideration:

See previous response for paragraph 64.

Consideration of External Networks and sub-100 kV Facilities and Contingencies in Operational Planning Analysis

Para 67: In proposed Reliability Standard TOP-002-3, Requirement R1, NERC proposes to require transmission operators to prepare an Operational Planning Analysis, i.e., next day study, which represents "projected System conditions" to determine if their planned operations will exceed facility ratings and stability limits for normal and contingency conditions. NERC does not indicate whether this includes external networks or sub-100 kV facilities.

SDT consideration:

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Proposed TOP-003-3 requires applicable entities to develop a data specification that covers its needs for monitoring and analysis purposes. There is no restriction on what voltage level or area that data can be pulled from. Proposed TOP-003-3, Requirement R5 shows a Transmission Operator being required to supply requested data to another Transmission Operator which clearly shows that a Transmission Operator can request and receive data from outside of its immediate area. The original SDTs have been clear in response to questions on this matter that they did not intend to place any restrictions on the type and location of data involved as long as the request was reliability based. However, to clear up any possible misconceptions, the Project 2014-03 SDT has amended proposed TOP-003-3, Requirement R1, Part 1.1 to explicitly specify that non-BES data and external data should be part of the data specification for Transmission Operators. Similar requirements exist in proposed IRO-010-2 for the Reliability Coordinator.

> Proposed TOP-003-3, Requirement R1, Part 1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
>
> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Concerns were raised during the Technical Conferences that proposed TOP-003-2 did not require that an entity actually use the data acquired in its monitoring and analysis functions. The Project 2014-03 SDT believes that the qualifiers placed in proposed TOP-003-3, Requirement R1, Part 1.1 (shown above) citing that the data specified is to support Operational Planning Analysis, Real-time Monitoring, and Real-time Assessments indicate that the data is to be used and that no further action is required on that particular issue.

However, the question arises as to what non-BES data and external network data is required. Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. Approved FAC-011-2, Requirement R3, Part 3.4 states that the level of detail required in system models for determination of SOLs must be part of the Reliability Coordinator's methodology which will determine what, if any, non-BES data is needed. Approved FAC-011-2, Requirement R4, Part 4.3 then requires the Reliability Coordinator to issue its SOL methodology to Transmission Operators who will follow the methodology in its work in determining SOLs. This combination of requirements will dictate what non-BES and external network data a Transmission Operator needs to acquire (if any).

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.
>
> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

Approved FAC-011-2, Requirement R3, Part 3.4: Level of detail of system models used to determine SOLs.

Approved FAC-011-2, Requirement R4, Part 4.3: Each Transmission Operator that operates in the Reliability Coordinator Area.

Para 68: In Order No. 693, the Commission directed a modification to planned outage coordination to require consideration of facilities below 100 kV that, in the opinion of the registered entity (such as a transmission operator) "will have a direct impact on the reliability of the Bulk-Power System…. The 2011 Southwest Outage Blackout Report includes similar recommendations that transmission operators should ensure their next-day studies include updated external networks and internal and external facilities (including those below 100 kV) that can impact Bulk-Power System reliability.

SDT consideration:

See previous response for data (paragraph 67).

In addition, the Project 2014-03 SDT has developed a new standard, IRO-017-1 Outage Coordination, to address all aspects of outage coordination between the Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, and Transmission Planner.

Para 69: The Commission seeks clarification and technical explanation from NERC whether the term "projected System conditions" in proposed Reliability Standard TOP-002-3 Requirement R1 includes updated external networks to reflect operating conditions external to their systems and sub-100 kV facilities (internal and external) in their operational planning analyses. If not, the Commission seeks comment on the associated reliability risks and, whether it is appropriate to include updated external networks to reflect operating conditions and external and sub-100 kV facilities (internal and external) in the operational planning analyses.

SDT consideration:

See previous responses under this heading.

Operating to Respect the Most Severe Single Contingency in Real-time Operations and Unknown Operating States

Para 70: NERC proposes to delete Reliability Standard TOP-004-2, Requirement R2, which provides that each transmission operator "shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency." NERC's Petition does not provide an explanation for the deletion. However, the NERC "mapping document," which is included as an exhibit to the TOP Petition indicates that NERC intends that Requirement R2 be replaced by proposed Reliability Standards TOP-001-2, Requirements R7 and R9.

SDT consideration:

The Project 2014-03 SDT believes that the concept of stating an explicit requirement to operate to the most severe single Contingency is not necessary as the FAC standards require an entity to analyze and operate for all Contingencies and not just the most severe single Contingency. The definitions of Operational Planning Analysis and Real-time Assessment have been strengthened to clarify this point.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed: Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Para 73: NERC has proposed to retire three key rules here, i.e., the requirements to be ready for the single largest contingency …

SDT consideration:

See previous response.

… to move quickly from an "unknown operating state" to within proven limits …

SDT consideration:

The Project 2014-03 SDT believes that there is always a set of limits in service and asserts that an operator, given a condition that has not been previously studied, is obligated to adhere to the set of limits in service at the time of the event. The SDT has produced an SOL Exceedance White Paper that explains how an SOL Exceedance is to be determined and what to do upon experiencing an SOL exceedance. The SDT believes that the situation has been covered in the proposed standards and requirements and that no further action is required. Specifically, the SDT points to proposed TOP-001-3, Requirements R12 and R13 as well as the guidance provided on Operating Plans in proposed TOP-001-3, Section F.

Proposed TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3, Section F: Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures, including electronic data exchange, which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative

> burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

… and to determine the cause of SOL violations in all time-frames, including real-time. We believe these three rules represent the bedrock core of real-time operating rules and practices, and it is therefore incumbent upon NERC to provide a more thorough and comprehensive explanation of how the proposed replacement standards compare in meeting the same objectives as the current standards.

<u>SDT consideration:</u>

The Project 2014-03 SDT agrees that a Transmission Operator needs to take appropriate action to mitigate the exceedance but does not agree to the inclusion of determining the 'cause' of the violation in Real-time. Real-time is not when to investigate or to do detailed analysis – but instead is the time to 'fix' the problem. Causes can be determined later and off-line. The Project 2014-03 SDT, as previously stated, has agreed to include the concept of Real-time Assessment for Transmission Operators. This assessment is believed to be sufficient in identifying 'cause' for operators in Real-time. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 74: In particular, NERC should address whether its proposal would allow a different approach to real-time operational assessments and operation to the most severe single contingencies and, if so, NERC should explain and technically support the nature and associated reliability effects of any different approaches.

<u>SDT consideration:</u>

The Project 2014-03 SDT does not feel that it is advocating a different approach as shown in the previous responses above.

How are the proposed requirements to not exceed IROLs or certain SOLs for more than the specified times are the functional or implicit equivalent of the current rules?

<u>SDT consideration:</u>

The Project 2014-03 SDT has added all SOLs thus addressing this issue.

For example, do the proposed rules allow reliance on post-contingency mitigation at times when the current rules would require pre-contingency mitigation?

<u>SDT consideration:</u>

The Project 2014-03 SDT sees this item as having been addressed due to the commitments made above such as adding all SOLs to the standards and performing Real-time Assessments.

In addition, approved FAC-011-2, Requirement R2 compels the Reliability Coordinator to develop an SOL methodology that considers voltage, thermal, and Stability limits (including voltage) while demonstrating that the BES remains stable (transient, dynamic, and voltage) during pre-contingent (Requirement R2, Part 2.1) and post-contingent (Requirement R2, Part 2.2) conditions. Approved FAC-014-2, Requirement R2 requires each Transmission Operator to establish SOLs for its Transmission system that are consistent with the established Reliability Coordinator SOL methodology. Approved FAC-014-2, Requirement R5, Part 2 compels the Transmission Operator to communicate its SOLs to its Reliability Coordinator and Transmission Service Provider and approved FAC-014-2, Requirement R5, Part 1 compels the Reliability Coordinator to communicate the SOLs to neighboring Reliability Coordinators and other Transmission Operators among a list of other entities.

> Approved FAC-011-2, Requirement R2, and Parts 2.1 and 2.2:
> The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
> 2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES

condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

Approved FAC-014-2, Requirement R2: The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

Approved FAC-014-2, Requirement R5, Part 1: The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area.

If so, is the difference significant for reliability purposes?

SDT consideration:

See previous response.

Do both the current and proposed rules prohibit an entity from operating for more than 30 minutes in a state where loss of a particular line would cause the loss of enough resources or load to risk cascading outages or instability?

SDT consideration:

Yes, industry operates to T_v for all IROLs which is 30 minutes or less. By definition, only IROLs can cause Cascading or instability.

Or, if the entity is not yet operating beyond the pre-determined ratings of the particular line, would the proposed rules allow doing so while the current rules do not?

SDT consideration:

The Project 2014-03 SDT does not see that any changes are being suggested that would change the way these situations are handled today.

Should all transmission operators be required to run a real-time contingency analysis (RTCA) frequently, since the lack of such analysis can impair situational awareness substantially?

SDT consideration:

The SDT proposes to use approved IRO-008-1, Requirement R2 as the model for development for such capabilities for Transmission Operators as described above. See proposed TOP-001-3, Requirement R13 and the revised definition of Real-time Assessment.

Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed: Real-time Assessment - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Or is the value of such information outweighed for smaller entities with such limited facilities and operations that they generally can maintain similar reliability based on operator experience and judgment without any extra staffing and procedures needed to ensure that the RTCA's informational inputs and modeling are valid and useful?

SDT consideration:

Proposed TOP-001-3, Requirement R13 states that a Transmission Operator must perform a Real-time Assessment every 30 minutes. This is ‘what’ must be accomplished but doesn’t explain ‘how’ it can be done. That is left to the applicable entity. Smaller entities are free to devise equal and effective methods to accomplish this task. The ERO Rules of Procedure also allow them to contract out services for performing such assessments as long as they retain the responsibility for the final result. To clarify this concept, the Project 2014-03 SDT has added language to the definition of Real-time Assessment on the topic of contracted services.

> Proposed TOP-001-3, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
>
> **Proposed: Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Para 75: With regard to mitigation of unknown operating states, while NERC asserts that “unknown states” cannot exist, a transmission provider could have valid operating limits for all facilities but lack situational awareness when valid limits are exceeded. … the Commission seeks comment and technical explanation from NERC and other interested entities on the proposed retirement.

<u>SDT consideration:</u>

<u>See response to paragraph 73 above.</u>

The Project 2014-03 SDT believes that standards must be viewed in aggregate to provide the complete picture of what is covered. Approved EOP-008-1, Requirement R1, Part 1.6.2 covers the situation where backup or redundant capabilities are required.

Approved EOP-008-1, Requirement R1, Part 1.6.2: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

System Protection Coordination

Para 78: The Commission seeks comment and technical explanation from NERC and other interested entities on how current Reliability Standard PRC-001-1 Requirement R2's requirement for corrective action (i.e., return a system to a stable state) is addressed in its proposal. Further, the Commission proposes that NERC issue guidance on data needed for protection system coordination that addresses the applicable Order No. 693 directives and the proposed retirement of the Reliability Standard PRC-001-1 requirements.

SDT consideration:

Project 2014-03 SDT is no longer revising PRC-001-1. Project 2007-06 is responsible for PRC-001-1 revisions.

Notification of Emergencies

Para 80: NERC's proposed revisions warrant clarification. Read one way, proposed Requirement R3 is less comprehensive than the currently-effective requirements pertaining to notification of emergencies. Yet, it also contains provisions that, read another way, could require TOPs to notify others of all emergencies, not just day-ahead.

Para 81: Similarly, it is not clear whether proposed Reliability Standard TOP-001-2, Requirement R5 would address same-day and real-time operating emergencies not covered by TOP-001-2, Requirement R3. An Adverse Reliability Impact is an event that results in instability, or cascade conditions, while an Emergency includes conditions that could be a precursor to an Adverse Reliability Impact. Thus, the notification provisions of Requirement R5 do not cure the possible ambiguity in proposed Requirement R3.

Para 82: While NERC states that the obligation to notify for real-time emergency conditions was replaced by proposed Requirement R3, NERC does not indicate in its petition that the real-time or same-day obligation was purposely deleted or offer an explanation for the deletion. … We believe that, consistent with the currently-effective TOP Reliability Standards, the notification requirement of proposed Reliability Standard TOP-001-2 should apply to all emergencies, including real-time and same day emergencies. The Commission seeks comment from NERC and other interested entities regarding (1) the proper understanding of the scope of the notification provisions in the proposed requirements and (2) if the notification does not include all operational time horizons, technical justification for why transmission operators should not be required to notify reliability coordinators and other affected transmission operators of all emergencies in all operating time horizons.

SDT consideration:

The Project 2014-03 SDT has combined the previously proposed TOP-001-2, Requirements R3 & R5 into one requirement in proposed TOP-001-3, Requirement R8 that uses only actual and projected Emergency covering all time horizons.

Proposed TOP-001-3, Requirement R8: Each Transmission Operator shall inform its Reliability Coordinator, known impacted Balancing Authorities, and known other impacted Transmission Operators of its actual or expected operations that result in, or could result in, an Emergency.

Para 83: … NERC uses two different definitions of Adverse Reliability Impact in the TOP and IRO Petitions. … In addition, if the definition NERC is proposing no longer includes the phrase "uncontrolled separation" NERC should explain the removal of the statutory phrase "uncontrolled separation."

SDT consideration:

See previous response.

Primary Decision-Making Authority for Mitigation of IROLs/SOLs

Para 84: NERC's proposal contains a potential overlap in authority between the transmission operator and reliability coordinator with regard to the provisions pertaining to mitigation of IROLs and SOLs as set forth in the proposed TOP and IRO Standards.

Para 87: NERC's proposal with respect to mitigating IROLs appears to give both the transmission operator and reliability coordinator authority to act. Therefore, we seek clarification and technical explanation whether the reliability coordinator or the transmission operator has primary responsibility for IROLs.

SDT consideration:

The Reliability Coordinator has the responsibility for IROLs and the Transmission Operator has the responsibility for SOLs. This split in responsibilities is an important concept for the preservation of reliability within the BES and needs to be clear in the various standards and requirements. However, as discussed above, the Reliability Coordinator shall provide oversight on SOLs and assistance in mitigating SOLs as necessary.

See previous response to paragraph 43 on SOL overlap issues.

Planned Outage Coordination

Paragraph 90: The Commission is concerned with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a do not require coordination of outages. Outage coordination is a critical reliability function that should be performed by the reliability coordinator. Outage coordination is an integral part of the operational planning process with generation outages being scheduled from three to five years in advance and transmission maintenance and construction outages being scheduled one to three years in advance. Outages that have been planned well in advance still must go through a month-ahead, week-ahead, and sometimes even a day-ahead approval process depending on system topography and system conditions that may change as the scheduled maintenance outage approaches. For instance, forced outages often disrupt planned outage schedules. Therefore, the Commission believes it is essential that, as the functional entity with the wide-area view, the reliability coordinator coordinates this critical area of operational planning.

SDT consideration:

The SDT has developed a new standard, IRO-017-1 Outage Coordination, to address the overall topic of outage coordination. In addition, the SDT has revised proposed IRO-014-~~2~~3, Requirement R1, Part 1.4 to show that outage information must be made available and analyzed. Also, the Planning Coordinator and Transmission Planner have been added to proposed IRO-010-2 as applicable entities to ensure the sharing of planning information with the Reliability Coordinator.

Proposed IRO-014-~~2~~3, Requirement R1, Part 1.4: Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

Proposed IRO-017-1, Requirement R1: Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall:
1.1 Identify applicable roles and reporting responsibilities.
1.1.1 Development and communication of outage schedules.
1.1.2 Assignment of coordination responsibilities for outage schedules between Transmission Operator(s) and Balancing Authority(s).
1.2 Specify outage submission timing requirements.
1.3 Define the process to evaluate the impact of Transmission and generation outages within its Wide Area.
1.4 Define the process to coordinate the resolution of identified outage conflicts with its Transmission Operators and Balancing Authorities, and other Reliability Coordinators.

Proposed IRO-017-1, Requirement R2: Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

Proposed IRO-017-1, Requirement R3: Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators.

Proposed IRO-017-1, Requirement R4: Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective

Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-term Transmission Planning Horizon.

Secure Network

Paragraphs 92 & 93: Currently-effective Reliability Standard IRO-002-2, Requirement R2, requires that the data exchange between the reliability coordinator, transmission operator, and balancing authority be accomplished "via a secure network." According to NERC, the requirement to provide information via a "secure network" is now addressed in NERC Rules of Procedure, Section 1002 (Reliability Support Services). NERC also indicates that Requirement R2 is now addressed in proposed Reliability Standard IRO-014-2, Requirements R1, R2, and R3. Although NERC cites Section 1002 of the Rules of Procedure and proposed Reliability Standard IRO-014-2 as providing for the use of a secured data network, NERC does not explain how secured networks are covered in those sections. While Section 1002 of the NERC Rules and Reliability Standard IRO-014-2, Requirements R1, R2, and R3 address notification and exchange of information and data and coordination of actions, no language in these provisions appears to require the data exchange or notifications to be conducted in a secure mode.

SDT consideration:

The Project 2014-03 SDT understands the sensitivity around the concept of secure networks for transfer of data and has made appropriate changes to proposed TOP-003-3, Requirement R5, Part 5.3 and proposed IRO-010-2, Requirement R3, Part 3.3, to allow for the concept of security to be part of the mutually agreed upon data specification.

Proposed TOP-003-3, Requirement R5, Part 5.3: ~~Mutually agreeable security protocol(s).~~ A mutually agreeable security protocol.

Proposed IRO-010-2, Requirement R3, Part 3.3: ~~Mutually agreeable security protocol(s).~~ A mutually agreeable security protocol.

Reliability Coordinator Monitoring of SOLs

Paragraph 96: Although NERC's petition focuses on the appropriate entity to identify SOLs, it does not adequately explain the proposed retirement of the currently-effective Reliability Standard IRO-002-2 that establishes the obligation for reliability coordinators to monitor SOLs. With regard to NERC's explanation that Reliability Standard IRO-002-2 Requirement R4 is redundant with the requirements contained in IRO-010-1a and EOP-008-1, neither of these Reliability Standards requires the reliability coordinator to monitor SOLs.

SDT consideration:

The Project 2014-03 SDT believes that monitoring SOLs is intrinsic to the duties of a Reliability Coordinator as spelled out in Functional Model v5. However, to provide clarity, the Project 2014-03 SDT has provided explicit requirement language to address the need for monitoring SOLs at the Reliability Coordinator level. See proposed IRO-002-4, Requirement R4. As pointed out starting in paragraph 84 of the NOPR, only one entity can be responsible for SOLs and that is the Transmission Operator.

Approved FAC-011-2, Requirement R1 states that the Reliability Coordinator shall have a documented methodology for determining SOLs within its area. Approved FAC-011-2, Requirement R3, Part 3.1 states that the model used by the Reliability Coordinator must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study. These requirements will dictate what external data a Reliability Coordinator needs to acquire to effectively monitor SOLs.

Proposed IRO-010-2, Requirement R1, Parts 1.1 – 1.2 show additions to the data specification concept to clarify that external data, non-BES data, and applicable relay data are included.

> Proposed IRO-002-4, Requirement R3: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R1: The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area.

> Approved FAC-011-2, Requirement R3, Part 3.1: Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

> Proposed IRO-010-2, Requirement R1, Part 1.1: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses,

Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.

Proposed IRO-010-2, Requirement R1, Part 1.2: Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.

Standards Announcement

Project 2014-03 Revisions to TOP and IRO Standards
TOP-001-3

Final Ballot Now Open through January 21, 2015

Now Available

A final ballot for **TOP-001-3 – Transmission Operations** is open through **8 p.m. Eastern, Wednesday, January 21, 2015.**

The Standards Committee (SC) authorized a waiver to shorten the ballot for TOP-001-3. The ballot has been shortened to 7 days from 10 days. The notice of waiver request documents presented to the SC for consideration are posted below under "Supporting Documents."

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

The voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Ed Dobrowolski,
Standards Developer, or at 609-947-3673.

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Standards Announcement

Project 2014-03 Revisions to TOP/IRO Reliability Standards
TOP-001-3

Final Ballot Results

Now Available

A final ballot for **TOP-001-3 – Transmission Operations** concluded at **8 p.m. Eastern, Wednesday, January 21, 2015**.

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Quorum /Approval
84.70% / 72.69%

Background information for this project can be found on the project page.

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Ed Dobrowolski,
Standards Developer, or at 609-947-3673.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2014-03 TOP-001-3 Final_Ballot
Ballot Period:	1/15/2015 - 1/21/2015
Ballot Type:	Final
Total # Votes:	321
Total Ballot Pool:	379
Quorum:	**84.70 % The Quorum has been reached**
Weighted Segment Vote:	72.69 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	59	0.686	27	0.314	0	2	17
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	1	2
3 - Segment 3	83	1	48	0.727	18	0.273	0	6	11
4 - Segment 4	30	1	15	0.625	9	0.375	0	0	6
5 - Segment 5	82	1	42	0.646	23	0.354	0	4	13
6 - Segment 6	52	1	31	0.705	13	0.295	0	1	7
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	5	0.5	5	0.5	0	0	0	0	0
9 - Segment 9	3	0.2	2	0.2	0	0	0	1	0

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals	**379**	**7**	**212**	**5.089**	**93**	**1.911**	**0**	**16**	**58**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative,	Bob Solomon		

	Inc.			
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Negative	
1	NB Power Corporation	Alan MacNaughton	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Nebraska Public Power District	Jamison Cawley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	

1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN		
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	

3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	

3	Southern California Edison Company	Lujuanna Medina		
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Municipal Energy Agency of Nebraska	Robin L Spady		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Acciona Energy North America	George E Brown	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
				SUPPORTS

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	THIRD PARTY COMMENTS
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Con Edison Company of New York	Brian O'Boyle	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Nevada Power Co.	Richard Salgo	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
				SUPPORTS

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Michael D Melvin		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	

6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit L

Standard Drafting Team Roster for NERC Standards Development Project 2014-03

Project 2014-03 Revisions to TOP/IRO Standards Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
Chair - David Souder, Director - Operations	PJM 2750Monroe Blvd. Audubon, PA 19403	1.610.666.4795 David.souder@pjm.com	David Souder was appointed to the position of Director Operations Support for PJM Interconnection in March 2012. In this role, Mr. Souder has responsibility for the Transmission Operations, Generation, and Transmission Outage Analysis Departments. The aforementioned departments are responsible for the reliable and efficient coordination of transmission and generation outages, Automatic Generation Control, wind power forecasting, load forecasting applications, hydro scheduling, Transient Stability Analysis, Transmission Outage Analysis automation processes, Phasor Measurement Units, and numerous special studies/assignments. He is a current member of the NERC Operating Committee (OC), serving on the NERC OC Executive Committee. Mr. Souder also serves as the Chairman of the Eastern Interconnection Data Sharing Network Advisory Committee. Upon graduation from Drexel University with a Bachelor of Science in Electrical Engineering, he joined PJM Interconnection LLC, serving in a variety of engineering and supervisory roles. Over his 20+ year career, Mr. Souder has held roles within PJM Operations, specifically as an engineer in Performance and Operations Planning, Shift Supervisor Dispatch (2000), Chief System Operator Dispatch

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			(2003), Manager Operations Planning (2006), and Director Operations Planning (2012). Mr. Souder has also obtained an MBA from Villanova University in 1997.
Vice Chair - Andrew Pankratz, Senior Manager, System Operations	Florida Power and Light (FPL) 700 Universe Blvd Juno Beach, FL 33408	1.305.442.5920 andrew.pankratz@fpl.com	Andrew Pankratz is the Senior Manager System Operations for FPL. In this role, Mr. Pankratz has responsibility for the FPL Transmission System Operators and FRCC Reliability Coordinators as the Reliability Coordinator Agent. These groups are responsible for the next-day and real-time planning and reliable operation of the FPL transmission system and FRCC region. Mr. Pankratz maintains a NERC Reliability Operator certification. He is a current member of the FRCC Operating Reliability Subcommittee, Florida – Southern Coordinating Group, and FRCC System Operating Limits Task Force. He has also been the subject matter expert for multiple Transmission Operator/Balancing Authority audits and control center certifications. Upon graduation from the University of Florida with a Bachelor of Science in Electrical Engineering. Mr. Pankratz joined FPL as a Protection and Control Engineer. Over his 15+ year career, Mr. Pankratz has held various positions of increased responsibility such as Protection and Control Engineer, Reliability Leader, Transmission Scheduler/System Operator, System Operations Manager-Load Dispatch, System Operations Manager-Nextera Energy Resources, and Senior Manager System Operations.

Name and Title	Company and Address	Contact Info	Bio
David Bueche Consultant, Policy and Compliance	CenterPoint Energy Houston Electric LLC 1111 Louisiana St. Houston, TX 77002	1,.713.207.7851 David.bueche@centerpointenergy.com	David Bueche has over 12 years of experience in the electric utility industry where he has held positions including Real Time Shift Engineer, Operations Support Engineer, and Compliance Team Lead. Mr. Bueche has a Bachelor of Science degree in Electrical Engineering from Louisiana Tech University. Current responsibilities within CNP Policy and Compliance include: • Participating in the development of a comprehensive NERC Reliability Standards compliance program. • Collaborating with subject matter experts to demonstrate compliance through documentation, processes, and mandatory reporting. • Coordinating responses to PUCT, NERC, ERCOT, and FERC direct requests for information and orders. • Monitoring NERC and FERC developments for issues that impact or potentially impact CNP. • Developing and submitting comments and recommending voting positions on draft NERC Reliability Standards. Mr. Bueche began his career as a Shift Engineer where he worked alongside real time operating personnel at Entergy and Southwest Power Pool (SPP) performing various studies to mitigate concerns on the transmission grid in real

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			time up to the next day. As an Operations Support Engineer for SPP and The Electric Reliability Council of Texas (ERCOT), he performed various roles ranging from outage coordination, deriving System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) in the SPP Region, performing seven day studies, determining the most limiting zonal paths on the ERCOT transmission grid, and assisting in creating mitigating efforts for potential next day issues. As a Compliance Team Lead for Texas Reliability Entity, Mr. Bueche led NERC compliance audits for all registered functions in the ERCOT Region, Certifications of newly registered entities, and Spot Checks derived from Event Analysis results.
James Case Director, System Operations	Entergy Services, Inc. 5201 W. Barraque Street Pine Bluff, AR	1.870.541.3908 jcase@entergy.com	James Case was named Director of System Operations Center North in June, 2014. Immediately prior to being named to this position, Mr. Case served in transmission operations as Director, Transmission Operations Engineering, and led the implementation of integration into the MISO RTO for Entergy's transmission function. As Director of System Operations Center North, Mr. Case is responsible for the safe, reliable operation of the transmission grid in Entergy's four state territory, directing the transmission operator function along with regional transmission switching. Mr. Case has over forty years of electric utility experience, most recently in transmission operations. He has experience in all phases of transmission

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			and distribution, including field engineering, construction management, distribution standards, optimization of week-ahead security-constrained unit commitment and bulk power operations. In his last assignment, he directed a group of engineers responsible for maintaining the state estimator and advanced applications and the short term transmission planning function at Entergy. In addition to his previous assignment, he has served as Director of Weekly Procurement Process, Manager of Transmission Security Coordination, Staff Engineer in Distribution Standards, and District Engineer in the south-central district of Entergy Mississippi. Before joining Entergy, Mr. Case worked for the Union Carbide Nuclear Division and Gulf Power Company. Mr. Case is active nationally in NERC. He is Vice-Chair of the NERC Operating Committee, member of the NERC Reliability Issues Steering Committee, past Chair of the SERC Operating Committee, and past Chair of the NERC Real Time Operations Standards Drafting Team. Mr. Case has served as a member of the Reliability Coordination Standards Drafting Team, the Interconnected Reliable Operations Standards Drafting Team, the Version 0 Standards Drafting Team, the Reliability Coordination Working Group, the Congestion Management Working Group, and the ANSI C62 Working Group concerned with surge arrester standards.

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			Mr. Case has a Bachelor's Degree in Electrical Engineering from Mississippi State University and a Master's in Business Administration from the University of Arkansas at Little Rock. He is a senior member of Institute of Electrical and Electronics Engineers, Inc., member of the Power Engineering Society, and is a registered professional engineer in Mississippi. Mr. Case is a member of Eta Kappa Nu, Tau Beta Pi, Beta Gamma Sigma and Alpha Epsilon Lambda.
Allen Klassen Director, System Operations	Westar Energy 818 South Kansas Ave. Topeka, KS 66612	1.785.575.6073 Allen.Klassen@WestarEnergy.com	Allen Klassen was recently named Director of System Operations Support after serving 15 years as Manager and Director of Transmission System Operations for Westar Energy in Topeka, Kansas. In these roles, Mr. Klassen had responsibility for the safe and reliable operations of the Westar transmission network throughout the eastern portion of Kansas and coordinated operations with neighboring entities in the region. He supervised and worked closely with the Transmission Operators and guided improvements in operator training, outage coordination, and operator tools for network analysis. Along with operating responsibilities, Mr. Klassen is directly involved in NERC compliance activities including having served as the primary compliance contact, and the lead subject matter expert for all of the Readiness Reviews and Compliance Audits at Westar since 2005.

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			He is a current member of the NERC Critical Infrastructure Protection Committee (CIPC) as the Operations representative from the Southwest Power Pool (SPP). Mr. Klassen also serves as the Vice-Chair of the SPP Operating Reliability Working Group, and has participated on Balancing Authority and Transmission Operator certification teams for the SPP RE. Upon graduation from Kansas State University with a Bachelor of Science in Electrical Engineering, Mr. Klassen joined Southwestern Public Service Company (SPS) in Amarillo, Texas in 1984. He started in Distribution Operations and quickly moved into System Operations and began working with, and then supervising, the generation and transmission system operators. Mr. Klassen left SPS as the Manager of System Operations to continue his career at Westar Energy in 1999.
Bruce Larsen Manager – System Reliability	We Energies W237N1500 Busse Road – PEDC Waukesha, WI 53188	1.815.543.1154 Bruce.larsen@we-energies.com	Bruce Larsen is currently the Manager of System Reliability for We Energies, orchestrating the LBA functions for Southeast Wisconsin and the Upper Peninsula of Michigan. Mr. Larsen has spent almost 30 years in the electric industry. He has experience in generation (Operations) and training (Operations Group Lead), at Exelon's Byron Nuclear Station. Responsibilities included all facets of operations training and NRC compliance and response. Mr. Larsen also has experience in distribution and transmission system operations while at Com Ed's Bulk Power Operations

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			Facility. Mr. Larsen holds a Bachelor of Science in Business with a Math minor.
Jason Marshall Managing Director, Reliability Compliance	ACES 4140 West 99th Street Carmel, IN 46032	317-344-7204 jmarshall@acespower.com	Jason Marshall joined ACES in April 2011 and is currently Managing Director of Reliability Compliance. Mr. Marshall is currently responsible for leading ACE's reliability compliance support service which provides advice, guidance, training and reliability compliance consulting to ACE's Members. He has 18 years of experience in the energy industry including extensive experience in bulk power operations and ERO compliance. Mr. Marshall began his career in 1996 with Duke Energy as an Associate Engineer supporting its transmission tariff and bulk power operations. Immediately prior to joining ACES, Mr. Marshall held positions of progressively increasing responsibility in operations engineering and ERO standards development and compliance at Midwest ISO (now Midcontinent ISO). He also worked as a reliability coordinator for the MAIN Coordination Center. Mr. Marshall's industry experience includes reliability coordination, transmission operations, balancing authority operations, operations planning, EMS support, transmission tariff administration, and reliability policy analysis. He has served on numerous NERC, Regional Entity, and industry committees. Mr. Marshall currently serves on the NERC Members Representative Committee, Planning Committee, and Reliability Issues Steering Committee (RISC) and was an

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			inaugural member of the RISC. He also serves on the SERC Board of Directors. Mr. Marshall graduated with a Bachelor of Science degree in electrical engineering from Rose-Hulman Institute of Technology, a Master of Science in Electrical Engineering (with a power systems emphasis) from Clemson University and a Master of Business Administration from the University of Indianapolis. Mr. Marshall is a NERC Certified System Operator - Reliability and a Registered Professional Engineer in the states of North Carolina and Indiana.
Albert Peters Corporate Area Functional Leader, Transmission Operations	Arizona Public Service 2124 W. Cheryl Drive Phoenix, AZ 85021-1808 MS: 3260	1.602.250.1112 Albert.peters@aps.co	Albert Peters joined Arizona Public Service in May of 1985 and is currently serving as the Corporate Area Functional Leader for the Transmission Operations area where he is responsible for process and procedural oversight ensuring operational effectiveness and represents the company as the subject matter expert for regional standards and compliance. Previously, Mr. Peters served as the Transmission Operations Section Leader where he was responsible for the safe reliable operation of the APS transmission system. He served 13 years as the Chief Dispatcher for APS and currently serves as the APS representative on the WECC Operating Committee. Mr. Peters served 5 years on the WECC Reliability Coordinator Sub-Committee and as an auditor team member on 4 NERC readiness audits. Mr. Peters served and continues to serve as the Subject Matter Expert for NERC audits. He is also

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			certified as a certification team member for WECC, and has participated as a team member in the certification of 5 companies registering to operate in the western interconnection including Balancing Authority, Transmission Operator, and Reliability Coordinator certifications.
Robert Rhodes Manager, Reliability Standards	Southwest Power Pool 201 Worthen Drive Little Rock, AR 72223-4936	1.501.614.3241 Rrhodes@spp.org	Robert Rhodes is the Manager of Reliability Standards at Southwest Power Pool (SPP) where he has been employed since 2000. In his previous role at SPP he was Manager of Reliability Coordination for over 10 years. Prior to joining SPP, Mr. Rhodes worked at Progress Energy (Carolina Power & Light Company) in Raleigh, NC for over 26 years in various positions in transmission maintenance, operations, and planning. In his current capacity, Mr. Rhodes works with SPP members, SPP staff, and other industry experts to ensure that reliability standards necessary to maintain a reliable bulk electric system are in place. Mr. Rhodes coordinates SPP members and registered entities in the development, refinement, maintenance, communication, training and implementation of national and regional reliability standards and policies. He is active at NERC currently serving on the Operating Reliability Subcommittee (ORS), the ORS Executive Committee, the Resources Subcommittee, the Standards Committee Process Subcommittee, the Physical Security Standard Drafting Team, and the TOP/IRO Revisions

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			Standard Drafting Team. Mr. Rhodes previously served on the Reliability Coordination Standard Drafting Team and the Operating Personnel Communications Protocols Standard Drafting Team. He has also served on the Reliability Coordinator Working Group, the Interchange Distribution Calculator Working Group, and was Vice Chair of the Distribution Factor Working Group. Additionally, Mr. Rhodes has served on committees, working groups and task forces in SPP, SERC, and VACAR. Mr. Rhodes received an Associate in Science degree from Rockingham Community College in 1970, a Bachelor of Science degree in Electrical Engineering from North Carolina State University in 1972, and a Master of Engineering degree from Rensselaer Polytechnic Institute in 1974. Mr. Rhodes is a member of Tau Beta Pi, Eta Kappa Nu, Order of the Engineer, the Institute of Electrical and Electronics Engineers and its Power Engineering Society, and the National Society of Professional Engineers. Mr. Rhodes is a NERC Certified System Operator (Reliability) and is a registered professional engineer in the State of North Carolina.
Kyle Russell Senior Technical Officer	Independent Electricity System Operator	1.905.855.6475 kyle.russell@ieso.ca	Kyle Russell is a Senior Technical Officer at Ontario's Independent Electricity System Operator (IESO) since 2000 and has over 20 years of industry experience. Mr. Russell spent 8 years in nuclear operations at the Pickering Nuclear Generating Station before joining the IESO. At the IESO he

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	Station A, Box 4474, Toronto, ON M5W 4E5		has been involved in real time system and market operations as a NERC Certified System Operator-Reliability, operations planning, post market settlement, NERC compliance audit preparation, emergency preparedness and managing interconnection and operating agreements for the IESO. He is a member of NPCC's Operational Review, Coordination and Assessment Working Group and is a past member of NPCC's Operational Planning Working Group.
Eric Senkowicz Director - Operations	FRCC Bayport Plaza 3000 Bayport Drive, Suite 600 Tampa, Florida 33607-8407.	1.813.207.7980 esenkowicz@frcc.com	Eric Senkowicz has been with the Florida Reliability Coordinating Council (FRCC) Member Services Division since 2005. Mr. Senkowicz was appointed Director of Operations in 2010. His primary responsibilities include the FRCC Reliability Coordinator function as well as facilitator and liaison to various operating committees and reliability groups within the FRCC Region and structure. He has been active in representing FRCC reliability within the NERC standards development process and has been active on various NERC reliability standards drafting teams and working groups as well as an active participant on several NERC reliability initiatives. Mr. Senkowicz has been working in the utility industry for over 19 years. His experience includes nuclear plant design engineering, systems engineer, component failure analysis specialist, and protective relaying installation and maintenance. His experience also includes five years in grid

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			operations with various responsibilities including load forecasting, system dispatch, transmission operations, operations planning, and as a system operator for a large Florida utility (approximate 20,000 MW peak load system). Prior to joining the FRCC staff, Mr. Senkowicz worked for FPL, the FRCC Reliability Coordinator Agent and spent three years as an on-shift FRCC Regional Reliability Coordinator based out of Miami, Florida. Mr. Senkowicz holds a degree in Electrical Engineering and is a NERC Certified System Operator, Reliability. Mr. Senkowicz is also a registered Professional Engineer in the State of Florida.
Kevin Sherd Director – Forward Operations Planning	MISO P.O. Box 4202 Carmel, IN 46082	1.317.249.5765 ksherd@misoenergy.org	Kevin Sherd was named Director of Forward Operations Planning for MISO in April 2013. In this role, Mr. Sherd has responsibility for Outage Coordination, Next-Day Security Planning, Transmission Scheduling, and Seams Administration. He currently chairs the Reliability Committee of ReliabilityFirst. Mr. Sherd graduated from Cedarville University with a Bachelor of Science in Electrical Engineering, then from Wright State University with a Master of Science in Electrical Engineering. After beginning his career with Dayton Power & Light in 1996, Mr. Sherd has held various roles in real-time operations, operations support, short-term planning, and long-term planning.